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NATIONAL ENERGY POLICY ACT OF 1989 (PURPA)

HEARINGS

BEFORE THE

COMMITTEE ON ENERGY AND NATURAL RESOURCES UNITED STATES SENATE

ONE HUNDRED FIRST CONGRESS

FIRST SESSION

ON

S. 324

TO ESTABLISH A NATIONAL ENERGY POLICY TO REDUCE GLOBAL WARMING, AND FOR OTHER PURPOSES

OCTOBER 26, AND NOVEMBER 7, 1989

PART 2

Printed for the use of the
Committee on Energy and Natural Resources

U.S. GOVERNMENT PRINTING OFFICE
25-627 WASHINGTON : 1990

S311-12

For sale by the Superintendent of Documents, Congressional Sales Office
U.S. Government Printing Office, Washington, DC 20402

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NATIONAL ENERGY POLICY ACT OF 1989 (PURPA)

THURSDAY, OCTOBER 26, 1989

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The Committee met, pursuant to notice, at 9:30 a.m., in room SD-366, Dirksen Senate Office Building, Hon. Timothy E. Wirth presiding.

OPENING STATEMENT OF HON. TIMOTHY E. WIRTH, U.S. SENATOR FROM COLORADO

Senator WIRTH. The committee will come to order.

Thank you all very much for being here. Today marks the continuation of our legislative hearings on the National Energy Policy Act, a bill designed to address the problem of global warming.

The implementation of that legislation is what we are after today with some very, very specific questions. Global warming has risen to the forefront of the international policy agenda with really quite striking speed.

Ten days from now an unprecedented event will be held in the Netherlands, with more than 70 environmental ministers meeting to discuss collaborative international efforts to address the threat of global warming.

This meeting, and others like it, demonstrate that the majority of nations view this as a problem of great urgency, a problem that must be addressed. That is why many of us were disappointed to learn, as we did yesterday, that this Administration apparently does not want to assert a leadership role for the United States in this process.

The Administration seems to think that the problem is not real and the concern will go away. The evidence clearly suggests otherwise.

In previous hearings, this Committee has learned from the best government and outside scientists that the question is not whether the earth will warm, but how much, how fast? Steps to prevent rapid, catastrophic global warming must be taken, and we need to begin now.

Every year, every month, every week or every day that we wait, the problem grows. Leadership is needed from the highest levels of government, and we certainly would expect that from this Administration.

I am very pleased that our Chairman has exercised a great deal of leadership in pushing this Committee. We are poised to take action, and today we are embarking on the process of refining a prudent response to the global warming threat.

Our role on this Committee in overseeing the way that we use energy in this country has enormous relevance to global warming. The burning of fossil fuels contributes more than 70 percent of the carbon dioxide generated by human beings, and carbon dioxide is the primary greenhouse gas.

As we look for ways to reduce greenhouse gas emissions in the energy sector there is little debate about the most cost-effective and justifiable action we can take: energy efficiency. The United States, which uses energy very inefficiently as compared to our major trading partners, must embark upon a major program to get more energy services while using less energy. Energy efficiency is our first line of attack.

Our Secretary of State, James Baker, and Energy Secretary Admiral Watkins have publicly stated that energy efficiency makes sense as a response to the global warming threat. The environmental community supports energy efficiency. Utilities themselves, despite some regulatory barriers, are looking also for new ways to save energy.

Unfortunately, virtually every analyst agrees that we are not acquiring all of the cost-effective energy improvements that are available in the marketplace. Today, we are going to begin exploring in detail those issues.

Subtitle B, Title III of S. 324 is designed to provide a flexible state-controlled initiative on energy efficiency. The basic thrust of these provisions is to encourage equal treatment of supply and demand-side resources. If we can craft these provisions properly we can realize the environmental, economic and competitive benefits of energy efficiency.

I look forward to working with our witnesses and have had a chance to talk to them little before about what I think are the cutting edge issues we want to get this morning. I hope we can finish this job and report out legislation before Congress adjourns.

We are pleased to have with us today Linda Stuntz, the Deputy Under Secretary of Energy for Policy and J. Steve Herod, Director of the Office of Electric Power Regulation at the Federal Energy Regulatory Commission.

Ms. Stuntz is accompanied by Ted Williams, the Director of Environmental Analysis at DOE and we look forward to your testimony.

Before moving to that, I would ask the distinguished ranking member of the Committee, Senator McClure, or our good colleague from the State of Montana if either of them have opening statements they might like to make?

[The prepared statement of Senator Wirth follows:]

STA MENT OF THE HONORABLE TIMOTHY E. WIRTH

Good morning. Today, we are continuing a series of legislative hearings on the "National Energy Policy Act," a bill designed to address the problem of global warming.

Global warming has risen to the forefront of the international policy agenda with great speed. 10 days from now, an unprecedented event will be held in the Netherlands with more than 70 environmental ministers meeting to discuss collaborative international efforts to address the threat of rapid global warming. This meeting, and other like it, demonstrate that the majority of nations view this as a problem of great urgency, a problem that must be addressed. That is why many of us are disappointed that to learn, as we did yesterday, that the Administration does not want to assert a leadership role for the United States in this process. The Administration seems to think that the problem will go away.

It will not go away. In previous hearings, this committee has learned from the best atmospheric scientists in this country, that the question is not whether the earth will warm, but by how much and how fast. In other words, this issue must be addressed and it must be addressed now. Every year, every day that we wait, the problem grows. Leadership is needed from the highest levels of government. And, to date, that leadership has not materialized from the Administration.

To respond to the problem, we must look at all sources of greenhouse gas emissions. For this committee, our role in overseeing the energy sector takes on new meaning. The burning of fossil fuels contributes more than 70 percent of the carbon dioxide generated by human beings. Carbon dioxide is the primary greenhouse gas.

As we look for ways to reduce greenhouse gas emissions in the energy sector, there is little debate about the most cost-effective and justifiable action we can take: energy efficiency. The United States, which uses energy very inefficiently when compared to our major trading partners, must embark upon a major program to get more energy services while using less energy. Energy efficiency is our first line of attack on global warming.

Our Secretary of State, James Baker, and Energy Secretary, Admiral James Watkins, have publicly stated that energy efficiency makes sense as a response to the global warming threat. The environmental community supports energy efficiency. Utilities themselves, despite regulatory barriers, are looking for new ways to save energy.

Unfortunately, virtually every analyst agrees that we are not acquiring all of the cost-effective energy efficiency improvements that are available in the marketplace. Today, we are going to begin exploring these issues in depth. Subpart B, Title III of S. 324 is designed to provide a flexible, state-controlled response to encourage greater efficiency. The basic thrust of these provisions is to encourage equal treatment of supply and demand side resources. If we can craft these provisions properly, we can realize the environmental, economic and competitive benefits of energy efficiency.

I look forward to working with our witnesses and others to realize these goals. We are pleased to have with us today, Linda Stuntz, Deputy Undersecretary of Energy for Policy and Steve Herod, Director of the Office of Electric Power Regulation at the Federal Energy Regulatory Commission. Ms. Stuntz is accompanied by Ted Williams, Director of Environmental Analysis at DOE. Welcome, we look forward to your testimony.

Senator Tim Wirth

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FOR RELEASE:
TUESDAY, OCTOBER 24, 1989
CONTACT: LISA CAPUTO
STEPHANIE RUDNICK
(202) 224-5852

STATEMENT OF SENATOR TIMOTHY E. WIRTH

MR. WIRTH: Mr. President, the next opportunity for the United States to establish a leadership role in the effort to protect the global environment is fast approaching. Two weeks from today, the Dutch will host a major international meeting for more than 70 environmental ministers from around the globe. The United States must go to that meeting with a strong, coherent policy. It is time to draw a map for our environmental future. And the United States should be, as it always has, at the forefront of the effort to make the world a more peaceful and habitable place.

But I am not optimistic about that happening. Throughout the year, the Administration's position on global warming has been responding to the initiatives of other nations. While virtually every scientist in the world agrees that we have a serious problem to address, this Administration has been dragging its feet, mired in stale questions about whether or not the greenhouse effect is a threat to this and other nations. And a pattern is emerging in which the Administration makes bold pronouncements about the urgency of the problem but fails to offer a policy for the international consideration. Responses have not matched the rhetoric.

As we approach yet another opportunity for the assertion of leadership, the Administration is in a quandry about what to do. There are some indications that this state of disarray has led some to question whether or not our very capable EPA Administrator should attend the Dutch meeting at all. That, Mr. President, would be a disaster. It is clear to this Senator that the rest of the world is waiting for the United States to make the first move and to lead other nations into the common battle to protect our shared environmental systems.

Some representatives of the Administration have recognized this fact. Earlier this year, Secretary of State James Baker and the Secretary of Energy, Admiral Watkins, issued public statements outlining some of the responses that are justified today. And at the Paris Economic Summit, President Bush joined with his G-7 colleagues to endorse: "common effort to limit emissions of carbon dioxide and other greenhouse gases." The G-7 communique described global environmental problems as serious threats that require "decisive action."

Last year, then candidate Bush said: "Those who don't think we can do anything about the greenhouse effect don't know about the White House effect." I know we can do something about the greenhouse effect, but we sorely need to learn more about the White House effect.

The White House effect thus far has not been impressive. We've had the alteration of testimony before the Senate by one of NASA's most

MORE

respected climatologists. We've had delayed responses about the negotiation of an international treaty to address the global warming phenomenon. We were told that the Administration would host a major international workshop. Indeed, the Chief of Staff, Mr. Sununu, urged our representatives to an international meeting on global warming to: "make every effort to obtain agreement on a global warming workshop on global warming this fall hosted by the United States." A pledge that President Bush made last fall on the campaign trail. But no workshop has been held in the United States, and none is forthcoming.

Mr. President, we're getting the wool pulled over our heads by a group that has its head in the sand. It is time for a change. We are sitting on the brink of a new age. The issues that defined a generation, arms control, Cold War tension, regional conflict are fading into the past. The new agenda is rooted in common efforts to abate forces that are grave threats to our society: drug trafficking and environmental decline.

The United States has to be the point man in the drive to summon a global will, a new direction for international cooperation on these efforts. It can't happen until this country, the most significant political entity on the planet, takes the lead.

Reports coming out of the White House are not encouraging. At every critical juncture this year, I have heard reports about an Administration groping for a policy. We should not have to develop a global warming policy for each and every international meeting that comes down the pike. An overall approach to this problem must be developed and clearly articulated to the public. Common sense, not polling data, suggests that we need to act now to slow down global warming trends. The only way to do that is to reduce emissions of carbon dioxide and other greenhouse gases.

The administration should commit immediately to begin negotiations to reduce greenhouse gas emissions. It is that simple. To be leaders, we needn't lock ourselves into draconian commitments. Rather, we can urge all nations to join us in implementing plans to phase out CFCs as soon as possible, we can call for the immediate deployment of energy efficient technology and we can agree to a concerted international effort to increase the amount of forested acreage around the world.

In two weeks, we have a major opportunity to seize the international high ground on global environmental concerns. A coherent U.S. policy is urgently needed. I hope my colleagues will join me in urging the Administration to stand up and be counted.

United States Senate
WASHINGTON, D.C. 20510-0603
OFFICIAL BUSINESS

TIMOTHY E. WIRTH
COLORADO

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ENERGY AND
NATURAL RESOURCES

United States Senate
WASHINGTON, DC 20510

Summary of National Energy Policy Act of 1989

The overall purpose of this Act is to **establish a national energy policy that will reduce the generation of carbon dioxide and trace gases as quickly as possible in order to slow the pace and degree of atmospheric warming and global climate change.** The bill focuses on energy efficiency, fuel switching, and conservation; use of nuclear, innovative clean coal and renewable energy technologies; reforestation and natural resource management policies; and international development and population practices to promote national and international growth and development, achieve a secure energy supply, and protect the global environment.

Title I requires the **development of a "Least-Cost National Energy Plan" designed to meet the goal of a 20 percent reduction in CO2 generation by the year 2000** through a mix of Federal and State energy policies. The Plan would outline policies for conserving fossil fuel energy and expanding the use of renewable energy sources in order to meet short-, medium-, and long-term domestic energy demands without exceeding the CO2 emissions levels outlined in this bill.

Title II establishes an **Office of Climate Protection at the Department of Energy** for purposes of monitoring U.S. energy policy for atmospheric and global warming effects and for directing Departmental policy with regard to strategies for reducing generation of CO2 and trace gases.

Title III provides for the **establishment and financing of energy efficiency research and development projects**, and for the establishment of eight regional centers which will develop techniques for improving the energy efficiency of industrial processes. This title also provides for the **repeal of the existing prohibition on sale and installation of energy conservation measures by utilities and for the purchase of "qualifying conservation" by utilities under section 210 of PURPA.**

Title IV establishes **national energy research and development priorities for the Secretary of Energy** designed to reduce the generation of carbon dioxide and trace gases.

Title V is designed to update and revitalize the state energy conservation programs (SECP) established in 1976 under EPCA. The title **require states to update their energy conservation plans and establish new energy conservation targets to replace those which expired in 1980.** In addition, title V also consolidates the Energy Extension Service and the Supplemental State Energy Conservation Plans into the SECP, **establishes State Energy Advisory Boards** to recommend programs and policies to achieve energy conservation goals and to coordinate state and federal efforts, and authorizes several new optional programs for inclusion into State Energy Conservation Plans.

Title VI would **authorize approximately $450 million between fiscal 1991 and fiscal 1993 for research and development of renewable energy** sources such as wind, solar, photovoltaic, biomass, geothermal, and hydrogen fuel cells. Establishes a program for additional research on fuel cell technologies that employ alternative fuel sources.

Title VII provides for the **establishment and funding of a research and development program designed to provide the basis for a second generation of nuclear reactors that would be passively safe, modular, and cost-effective.** Approximately $100 million is authorized to be appropriated for fiscal year 1991 and not more than $200 million for each of the fiscal years 1992 and 1993.

Title VIII provides for a **comprehensive report to Congress on international collaboration in research, development, and demonstration projects into technology for the production of electricity from thermonuclear fusion.**

Title IX provides for a **comprehensive report to be submitted to Congress on the Department of Energy's Clean Coal Program and the program's likely implications for CO2 generation,** atmospheric warming and global climate change.

Title X provides $100 million for fiscal years 1991 through 1993 to fund demonstration projects on the feasibility of using natural gas as a fuel for mass transit systems, fleet use, and training programs for conversion of gas and diesel-fueled vehicles to natural gas. The program also encourages research, development, and demonstration of high efficiency heat engines for generating electricity.

Title XI directs the Secretary of the Interior to conduct a study of the ecological and environmental resources that would be affected by global climate change. This title directs the Secretary of Energy, in consultation with the Secretary of Agriculture, to submit an analysis of the potential for reducing the air conditioning needs of buildings by undertaking targeted urban tree plantings. In addition, title XI also provides for the management and resource conservation of the Tongass National Forest.

Title XII provides $275 million in additional funding over fiscal years 1991, 1992, and 1993, for new and continuing research initiatives at the National Aeronautics and Space Administration (NASA), National Oceanic and Atmospheric Administration (NOAA), United States Geological Survey (DOI/USGS), and the National Science Foundation (NSF) to study the mechanisms and implications of global warming and atmospheric change. In addition, the National Institute of Standards and Technology (NIST) would receive funding for the development of safe, non-ozone depleting substitutes for chlorofluorocarbons (CFCs).

Title XIII directs the Administrator of AID, in conjunction with the Secretaries of the Interior, Agriculture, and the Treasury to provide Congress with a comprehensive report on the world's tropical forests, and to establish inventory, conservation, and forest plans for each tropical country. This title also directs the appropriate agencies to create incentives to encourage afforestation and disincentives to discourage deforestation. The Agency for International development, the Export-Import Bank, and the Overseas Private Investment Corporation would be instructed to promote private investment in energy-efficiency technologies in developing countries.

Title XIV calls for the convening of a multilateral global climate protection conference, the convening of an international conference on nuclear power, a multilateral agreement to reduce emissions of oxides of nitrogen, a reassessment of the Montreal Protocol on Substances that Deplete the Ozone Layer, and the establishment of a special office at UNEP and WMO to monitor global CO2 emissions.

Title XV establishes the importance of population growth as a contributory factor in global warming and climate change and authorizes appropriations of more than $1.5 billion for international family planning and information services programs between fiscal years 1991 and 1993.

STATEMENT OF HON. JAMES A. McCLURE, U.S. SENATOR FROM IDAHO

Senator McClure. Mr. Chairman, just briefly, earlier this year I urged the Chairman to expand the scope of the Committee's hearings on global climate change. I wish to thank the Chairman for convening these hearings on the regulatory provisions of S. 324 and in particular those provisions amending the Public Utility Regulatory Policies Act of 1978.

I would ask unanimous consent that the balance of my statement be placed in the record at this point.

Senator Wirth. Without objection, so ordered.

[The prepared statement of Senator McClure follows:]

OPENING STATEMENT
SENATOR JAMES A. McCLURE (R-ID)
COMMITTEE ON ENERGY AND NATURAL RESOURCES
THURSDAY, OCTOBER 26, 1989

PURPA PROVISIONS OF S. 324

Good morning. Earlier this year I urged the Chairman to expand the scope of the Committee's hearings on global climate change. I therefore wish to thank the Chairman for convening these hearings on the regulatory provisions of S. 324 and, in particular, those provisions amending the Public Utilities Regulatory Policies Act of 1978.

Improvements in energy efficiency and least-cost energy supplies are important ingredients to an effective national energy strategy. While in some instances growth in energy demand can be more cheaply satisfied by improvements in the efficiency of both energy production and use than by new energy supply alternatives, it is unclear who will be the winners and losers, and whether the consumers receiving the benefits will be subsidized by other utility customers.

What is clear is that these proposals raise significant issues of equity that need to be fully understood before we, as a matter of national policy, adopt the proposals in S. 324. As I understand one proposal, electric and gas utilities would be empowered to pay customers, or third parties, or even itself for "saved" energy, just as electric utilities now pay under PURPA on an "avoided cost" basis for energy produced by small power producers and cogenerators. FERC would determine what energy conservation savings would qualify, and qualifying conservation savings would be limited to those achieved by entities other than the utility itself.

However, unlike current law that applies to independent commercial power sources, S. 324 applies to a whole universe of industrial, commercial and residential consumers, and electric and gas utilities. Areas of potential energy savings span the gamut from improvements in industrial processes, through upgraded insulation in homes, to more energy efficiency furnaces and light bulbs. Even those actions that already are cost-effective would qualify.

We are all aware that the enactment of PURPA produced results which were far different from the limited program envisioned by the

Congress in 1978. Therefore we cannot, indeed we must not, automatically assume that PURPA is an appropriate model for regulatory reforms to encourage more efficient use of not only electricity, but, also natural gas, as is proposed in S. 324.

In addition, questions need to be asked with respect to the use of PURPA to encourage State utility commissions to establish not only electric utility rates, but natural gas utility rates so as to foster least-cost energy supplies.

If we are going to enact legislation in this area, we also need to better understand the consequences of implementation of the legislation as now drafted. We need to determine what policies we agree on in this area. Finally, we need to assure that the legislation is drafted to achieve those policies, and only those policies.

From this perspective, I look forward to participating with the Chairman and Senator Wirth in the evolution of energy policy legislation that addresses the critical issues associated with projected global climate changes. I am pleased to report that we are close to agreement on a realistic alternative to S. 324. When this measure is ready, I hope it will be the subject of legislative hearings specifically focused on its provisions.

Thank you again for the opportunity to make these remarks and I look forward to hearing the testimony from today's witnesses.

Senator WIRTH. Senator Burns.

STATEMENT OF HON. CONRAD BURNS, U.S. SENATOR FROM MONTANA

Senator BURNS. Thank you, and I want to congratulate this Committee and of course the Energy Committee for expanding these hearings.

Just a couple of statements on my part: it was a couple of weeks ago, three weeks ago that I sponsored an alternative fuel conference at Montana State University in their School of Business.

Now, you would think that we would probably sponsor that in their School of Engineering, but we did it in the School of Business because we happened to believe that the marketplace will be the driving force of any change as we deal with the problem of global climate change, and the problem is real. There is no doubt about that. Everything points to it.

Fossil-based fuels, as we know, is the biggest cause and we know that we have a finite supply of fossil-based fuels and I happen to believe that alternative fuels that deal with the problems of carbon dioxide will be the wave of the future. In other words, I see no other way around it if we are to continue to fuel an economy and to keep the planet livable.

We do not want to get into an area, though, where leadership is construed as maybe sometimes the inability to allow the marketplace to drive research and development, into other areas for energy, so sometimes we get into a situation where—legislation and this type thing—and that is the reason I am very anxious to hear what the panelists have to say today and the direction we should be going, that does not curtail or deter our businesses of finding alternative fuels, so I appreciate your efforts in this, Mr. Chairman, and I look forward to hearing from the panelists.

Senator WIRTH. Thank you very much, Senator Burns, and the economic approach and the economic incentives that you speak of are precisely the directions in which we ought to be going.

As you know, Senator Heinz and I have done Project 88, a whole approach to looking at a series of environmental issues and figuring out where we might be able to find marketplace solutions. The Administration has picked up one of those in a very welcome way in the Clean Air Act in looking at tradeable permits, which heads us in the right direction.

Recycling of motor oil, legislation that Senator Heinz and I have drafted with the help of the people at DOE and at EPA, is another step in that direction, recycling of newspapers and creating a market for them—there are a whole series of areas in which, clearly, economics are going to drive what we do and that certainly must be the case here as well.

What we want to figure out today is, do we know enough to know how to build conservation into the rate base? That is one of the questions that Mr. Herod will have to answer. That is one of the purposes of the hearing, to hear from the experts and find out whether qualifying conservation can be implemented. The concept clearly bears a good deal of analysis and I really appreciate, Senator McClure, your urging as well that we have these hearings.

The Senator from Oklahoma.

STATEMENT OF HON. DON NICKLES, U.S. SENATOR FROM OKLAHOMA

Senator NICKLES. Mr. Chairman, thank you. I look forward to hearing what our witnesses have to say today and I see you have another day of hearings scheduled as well.

I will say at the outset that I think—well, I have a very extensive statement and I do not want to read it all. I will insert it in the record.

[The prepared statement of Senator Nickles follows:]

STATEMENT OF SENATOR DON NICKLES
HEARING ON THE PURPA PROVISIONS IN S. 324
COMMITTEE ON ENERGY AND NATURAL RESOURCES

October 26, 1989

Mr. Chairman, I hope this hearing will clarify the intent of the changes to the Public Utility Regulatory Policy Act (PURPA) contained in S. 324, the "National Energy Policy Act of 1989."

As drafted, these provisions appear to make several fundamental changes to PURPA. First, the PURPA amendments establish an entirely new category of entities that electric ratepayers would be obligated to pay money to, without receiving an additional watt of electricity. The bill gives the Federal Energy Regulatory Commission the absolute discretion to define this new category of individuals or firms, called "qualifying conservation entitites". The only guidelines in the bill for these entities is that they not be "primarily engaged in the generation or sale of electric power", unless they are cogeneration facilities or small power producers.

In addition, the provisions in S. 324 would appear to set new federal standards for electric rates by limiting utility costs to "least cost supply measures" that are defined as actions "taken to provide adequate and reliable service to consumers with the incurrence of lowest total costs to society." Moreover, this legislation would sweep into PURPA the regulation of rates charged by natural gas local distribution companies. Thus, it appears that this legislation could encourage or even force natural gas local distribution companies to abrogate gas contracts with suppliers whenever those contracts are above the "least cost supply", such as spot price plus a "gas inventory charge."

Only a few months ago, the Congress finally reached agreement on a schedule for removal of the remaining wellhead price controls. I would be very concerned if the legislation before us could have the effect of re-opening that decontrol compromise. It is my understanding that this hearing and the one scheduled for November 7 will focus only on the electric utility, as opposed to the gas utility, regulation imposed by this bill. Accordingly, Mr. Chairman, I request that the Committee schedule an additional hearing on Subtitle B of Title III of S. 324 to receive testimony on the changes in natural gas policy contained in that Subtitle.

I would further caution my colleagues that this legislation appears to contradict the purposes of the very section it amends. Section 210 of PURPA was enacted to "encourage cogeneration and small power production". Arguably, the proposed amendments could have the effect of ending this preference. For example, this legislation could result in situations where independent electric retailers would be forced to purchase power or conservation services under "the least cost supply measures" mandate, in lieu of higher-cost power from the large electricity wholesaler, which has been forced under rules implementing section 210 to accept high-priced power from qualified cogeneration facilities.

Similarly, the broad changes proposed in this legislation could impose harships on consumers of electricity generated by nuclear reactors who may already be struggling to finance their nuclear power plants. Those consumers would have to increase their payments for electricity according to the subsidies set up in this bill for conservation services, and also increase their share of the financing costs of the nuclear plant to the extent total electricity use is reduced. And these rate hikes are imposed in the name of reducing carbon dioxide, which is not even created by nuclear power plants.

Mr. Chairman, recent history of the FERC has taught us at least two lessons that should help direct our thinking with respect to these proposals. First, the Committee should be avoid conferring blanket authority to the FERC to create a new category of firms that can demand money from electric ratepayers. This bill gives little or no direction to the FERC on how to define "qualifying conservation entities". I cannot support provisions that are tantamount to conferring a taxing authority upon the FERC to raise the rates to certain electric ratepayers for such vague purposes.

Moreover, the marketplace rewards valid conservation measures that reduce electricity costs. Why does the federal government need to establish a subsidy for "qualifying conservation entities"? There may well be sound economic reasons why all such entities are not being rewarded in the marketplace. For example, this bill could reward businesses for closing or moving their energy intensive operations to obtain payments for creating "qualifying conservation". Perhaps homeowners could qualify for payments simply by switching their appliances from electricity to gas, a move which might not otherwise make economic or environmental sense.

A second lesson we have learned is that in the decade that the PURPA cogeneration provisions have been implemented, many utilities have been charged relatively high prices for cognerated electricity. For example, in the State of Oklahoma, where the depressed economy has resulted in a surplus of electric power generation, it is becoming a hardship on ratepayers to be forced to pay for additional, unneeded electric power from qualifying cogeneration facilities.

It is time that the Committee thoroughly review the need for continued subsidization of cogeneration facilities. Until the Committee has completed its review, it would be premature to even consider extending this subsidy concept to an additional, undefined category of conservation suppliers, much less to natural gas utilities.

Thank you, Mr. Chairman. I look forward to the witnesses' testimony.

Senator **Nickles**. Let me state at the outset that the proposal that would mandate payments for conservation would be a bad idea, and I will just leave it at that and look forward to hearing some statements and maybe I will refine that position, but I have a feeling that it probably will be strengthened as the course of the hearing goes on, but thank you, Mr. Chairman.

Senator **McClure**. Mr. Chairman, might I just add that as you know and as others are aware, there is a great deal of work that has already been done on trying to forge a consensus with respect to the provisions of S. 324, and I think it should be noted that we may be very close to a legislative expression of those discussions which would be introduced as a separate measure, and I would hope that when that is done, if it is done in the near future, as I hope that it can be, that we could have hearings that were focused on specific provisions of that legislation as well.

Senator **Wirth**. Well, Senator McClure, thank you very much. We appreciate your urgency, that this can be a reflection of the responsibility of this Committee.

Senator Metzenbaum?

STATEMENT OF HON. HOWARD M. METZENBAUM, U.S. SENATOR FROM OHIO

Senator **Metzenbaum**. Mr. Chairman, thank you for allowing me to participate in this meeting. I think it is commendable for you to be holding it.

When Congress passed PURPA in 1978, none of us really knew how great a contribution would soon be made toward our Nation's energy future by generation or co-generation in renewable energy sources.

Back then, there were many nay-sayers who argued the small independent power-producers make only a negligible contribution or would be unreliable, or they would be too costly after all. They argued if co-generation in renewables were really so competitive, then utilities would be already developing them.

The past decade has shown the nay-sayers to be wrong—very wrong. PURPA's regulations for qualifying facilities have not been without growing pains, but the results are in and in state after state there are these small independent producers that are saving utilities and their customers hundreds of millions of dollars in avoided construction and fuel cost by providing thousands of megawatts of reliable and clean power.

Now, as we approach the decade's challenge of how to best encourage utilities to invest in energy efficiency projects, Mr. Chairman, I hope these hearings will not be deja vu all over again.

I hope we will not be hearing the same arguments this time about energy-efficiency programs that we heard about small power producers: that their contribution will be negligible or impossible to measure, that they will be unreliable, that they will be too expensive, that utilities should be trusted to develop all conservation resources on their own.

These arguments are just as wrong now as they were a decade ago. We all know well the tremendous potential role for efficiency of investments in improving our economy and lessening our environmental problems, yet study after study shows that our Nation—we are underinvesting in efficiency.

Why is this? I will mention three important reasons: (1) customers often do not pay their own utility bills, (2) individuals, especially low and middle income, cannot afford to tie up their limited cash in conservation investments, and (3) many individuals and companies still do not know what are the most valuable and cost-effective investments to make.

All of these reasons argue strongly that utilities must play a central role in promoting and financing investments in energy efficiency. These investments deserve and demand financial support of the utility companies, whether they are made by independent parties, the customers or the utilities themselves.

For this to happen, Mr. Chairman, we must explore many policy options such as rate-basing conservation, allowing utilities to recover revenues they lost because of successful conservation programs, and fitting conservation into competitive auction plans.

I commend the Chairman for holding these important hearings. I hope they will help us in Congress catch up with state commissions and utility companies. I hope they will spur DOE and FERC to move back to center stage in forward-thinking utility policy.

I look forward to hearing from the witnesses. Thank you, Mr. Chairman.

Senator WIRTH. Thank you, Senator Metzenbaum. It was noted earlier today our witnesses today are Linda Stuntz and J. Steve Herod. Linda, why not start with you?

[The prepared statements of Senators Metzenbaum and Johnston follow:]

STATEMENT OF SENATOR HOWARD M. METZENBAUM
ENERGY AND NATURAL RESOURCES COMMITTEE
HEARING ON PURPA AND ENERGY EFFICIENCY

OCTOBER 26, 1989

WHEN CONGRESS PASSED PURPA IN 1978 NONE OF US REALLY KNEW HOW GREAT A CONTRIBUTION WOULD SOON BE MADE TOWARD OUR NATION'S ENERGY FUTURE BY COGENERATION AND RENEWABLE ENERGY SOURCES.

BACK THEN THERE WERE MANY NAY-SAYERS WHO ARGUED THAT THESE SMALL, INDEPENDENT POWER PRODUCERS WOULD MAKE ONLY A NEGLIGIBLE CONTRIBUTION. OR, THAT THEY WOULD PROVE TO BE UNRELIABLE. OR, THAT THEY WOULD BE TOO COSTLY. AFTER ALL, THEY ARGUED, IF COGENERATION AND RENEWABLES WERE REALLY SO COMPETITIVE THEN UTILITIES WOULD BE ALREADY DEVELOPING THEM.

WELL, THE PAST DECADE HAS SHOWN THE NAY-SAYERS TO BE WRONG. VERY WRONG.

PURPA'S REGULATIONS FOR QUALIFYING FACILITIES HAVE NOT BEEN WITHOUT GROWING PAINS AS FERC, STATE PUBLIC UTILITY COMMISSIONS, UTILITIES AND OTHERS WRESTLED WITH THE CHALLENGE OF CREATING A STARTUP INDUSTRY OF SMALL POWER PRODUCERS. BUT THE RESULTS ARE IN, AND IN STATE AFTER STATE THESE INDEPENDENT SMALL PRODUCERS ARE SAVING UTILITIES AND THEIR CUSTOMERS HUNDREDS OF MILLIONS OF DOLLARS IN AVOIDED CONSTRUCTION AND FUEL COSTS BY PROVIDING THOUSANDS OF MEGAWATTS OF RELIABLE AND CLEAN POWER.

NOW WE APPROACH THIS DECADE'S CHALLENGE OF HOW TO BEST ENCOURAGE UTILITIES TO INVEST IN ENERGY EFFICIENCY PROJECTS. MR. CHAIRMAN I HOPE THAT THESE HEARINGS WON'T BE "DEJA VU ALL OVER AGAIN."

I HOPE WE WON'T BE HEARING THE SAME ARGUMENTS THIS TIME ABOUT ENERGY EFFICIENCY PROGRAMS THAT WE HEARD ABOUT SMALL POWER PRODUCERS. THAT THEIR CONTRIBUTION WILL BE NEGLIGIBLE OR IMPOSSIBLE TO MEASURE. THAT THEY'LL BE UNRELIABLE. THAT THEY'LL BE TOO EXPENSIVE. THAT UTILITIES SHOULD BE TRUSTED TO DEVELOP ALL CONSERVATION RESOURCES ON THEIR OWN.

MR. CHAIRMAN, THESE ARGUMENTS ARE JUST AS WRONG NOW AS THEY

WERE A DECADE AGO. WE ALL KNOW WELL THE TREMENDOUS POTENTIAL ROLE FOR EFFICIENCY INVESTMENTS IN IMPROVING OUR ECONOMY AND LESSENING OUR ENVIRONMENTAL PROBLEMS.

YET STUDY AFTER STUDY SHOWS THAT AS A NATION WE ARE UNDER-INVESTING IN EFFICIENCY.

WHY IS THIS? I'LL MENTION THREE IMPORTANT REASONS. ONE, CUSTOMERS OFTEN DON'T PAY THEIR OWN UTILITY BILLS. TWO, INDIVIDUALS, ESPECIALLY LOW AND MIDDLE INCOME, CANNOT AFFORD TO TIE UP THEIR LIMITED CASH IN CONSERVATION INVESTMENTS. AND, THREE, MANY INDIVIDUALS AND COMPANIES STILL DON'T KNOW WHAT ARE THE MOST VALUABLE AND COST-EFFECTIVE INVESTMENTS TO MAKE.

ALL OF THESE REASONS ARGUE STRONGLY THAT UTILITIES MUST PLAY A CENTRAL ROLE IN PROMOTING AND FINANCING INVESTMENTS IN ENERGY EFFICIENCY. THESE INVESTMENTS DESERVE AND DEMAND THE FINANCIAL SUPPORT OF UTILITY COMPANIES WHETHER THEY ARE MADE BY INDEPENDENT PARTIES, THE CUSTOMERS, OR THE UTILITY ITSELF.

FOR THIS TO HAPPEN, MR. CHAIRMAN, WE MUST EXPLORE MANY POLICY OPTIONS, SUCH AS RATEBASING CONSERVATION, ALLOWING UTILITIES TO RECOVER REVENUES THEY LOST BECAUSE OF SUCCESSFUL CONSERVATION PROGRAMS, AND FITTING CONSERVATION INTO COMPETITIVE AUCTION PLANS.

I COMMEND THE CHAIRMAN FOR HOLDING THESE IMPORTANT HEARINGS. I HOPE THEY WILL HELP US IN CONGRESS CATCH UP WITH STATE COMMISSIONS AND UTILITY COMPANIES. I HOPE THEY WILL SPUR D.O.E. AND FERC TO MOVE BACK TO CENTER STAGE IN FORWARD THINKING UTILITY POLICY. I LOOK FORWARD TO HEARING FROM TODAY'S WITNESSES.

OPENING STATEMENT OF SENATOR J. BENNETT JOHNSTON
HEARING ON PURPA PROVISIONS OF S. 324,
THE "NATIONAL ENERGY POLICY ACT OF 1989"

We are here this morning to receive testimony on legislation that would amend the Public Utility Regulatory Policies Act of 1978, known by its acronym as PURPA. The bill before us, S. 324, the "National Energy Policy Act of 1989" includes two amendments to PURPA.

The first of these amendments appears to be non-controversial and addresses a general problem in utility ratemaking. Typically, electric and gas rates are structured so that utility earnings increase with the more gas or electricity a utility sells. There is, therefore, a disincentive for a utility to engage in least cost planning to the extent that the least cost resource in any given instance is a conservation measure which reduces utility sales. The first proposed amendment would simply require state utility commissions and unregulated utilities to consider changing ratemaking practices so as to remove the existing disincentive for least cost planning.

The second PURPA amendment is more problematic. It would create "qualifying conservation" which is to be treated analogously to qualifying facilities under the existing provisions of PURPA. Specifically, utilities would be required to buy qualifying conservation from "qualifying conservation entities" at rates ultimately determined by state commissions. Qualifying conservation is defined by the bill as a reduction in electric demand at any time that would not occur but for payments by a utility.

The initiation of a mandatory purchase program for conservation creates a host of serious concerns. For example, in the context of a mandatory program can the reliability of purchased conservation be guaranteed? As a practical matter can we separate conservation produced by utility payments from conservation that would occur anyway? Perhaps most importantly, can we devise a pricing regime which ensures that utilities are not required to buy conservation whose true cost exceeds the cost of supply side alternatives?

These questions and others are significant. They must be satisfactorily answered before we move forward with qualifying conservation. Our hearing this morning will help to achieve that purpose. I look forward to hearing from our witnesses.

STATEMENT OF LINDA G. STUNTZ, DEPUTY UNDER SECRETARY, POLICY, PLANNING AND ANALYSIS, DEPARTMENT OF ENERGY, ACCOMPANIED BY TED WILLIAMS, DIRECTOR, ENVIRONMENTAL ANALYSIS, AND DR. JOHN MILLHONE, DIRECTOR, OFFICE OF BUILDINGS AND COMMUNITY SYSTEMS

Ms. STUNTZ. Thank you, Senator Wirth and members of the panel. Good morning and thank you for the opportunity to provide the Department of Energy's position on S. 324 and its proposed amendments to PURPA.

At the outset, let me say that the Department of Energy takes very seriously the threat of potential global climate change. We are devoting significant resources to this effort, and I look forward to later discussing with you some of the initiatives that we have under way.

Subtitle B, turning specifically to the focus of today's hearing, of Title III, proposes that States adopt a Federal least-cost utility planning standard for regulated and unregulated natural gas and electric distributors and sellers.

I think the Members of this committee know that the Department is committed to least cost planning, integrated resource planning and various other names that have been given to recent experimental State activities in trying to make utilities indifferent as to whether they invest in conservation or in generation as a source of supply for their customers.

We recognize that creating a truly level playing field for conservation and demand-management investments can potentially reduce environmental emissions, lower utility bills, and foster more responsible use of our energy resources. That is one reason why the Department of Energy with Congress' urging has invested a significant amount of time and attention in a least cost utility planning program.

I have with me today Dr. John Millhone, Director of the Office of Buildings and Community Systems, who has been a driving force behind the Department's least-cost utility planning program and would be available to answer more detailed questions on that program.

As described in my written testimony, we have a significant and growing program under way to encourage experimentation and innovation at the State level in developing least cost plans and strategies. We see that the vast majority of States are already engaged in exploration of least-cost strategies at various levels, and there have been some encouraging signs of early success.

Some States are well along into implementation, including actually allowing conservation sources to compete with generation sources in bidding to supply customers with power as Central Maine Power Company has done, and is being considered by the Massachusetts Public Utility Commission.

For these reasons, the Department believes Federal legislation at this time would be premature. More particularly, we believe that the Federal standard proposed in S. 324 could lead to higher utility bills without providing compensating reductions in atmospheric emissions or with the truly least-cost energy sources.

We are also concerned that, given our current understanding of the difficulties in purchasing reliable quantities of conservation, there is a substantial opportunity for error inherent in the estimation of conservation achieved over time. We do not believe these problems are insoluble. There has been real progress made in measurement, and understanding over time how a given increment of conservation is sustained.

We are not sure, however, that we have the answers yet, and we think it is important that we have better answers because customers will pay real dollars for estimated conservation. There is, therefore, a chance of unintended consumer losses. The development of regulatory incentives is a complex and site-specific problem. It may depend upon the particular characteristics of each utility or the particular resources from which the utility can draw. For that reason, we believe at this time it is certainly best left to the individual States.

The Department is also concerned that S. 324 as drafted may subject emerging natural gas and electricity marketers and brokers to a new form of regulation. It is important to recognize that, unlike the original PURPA legislation, this is not legislation which gives QFs, (qualifying facilities), i.e., cogenerators and small power producers, a right to sell.

Rather, it potentially subjects those entities to a new kind of regulation, some kind of least-cost standard. We think that needs to be done thoughtfully and with clear understanding for the implications that might hold for this flourishing sector which has had competitive benefits and which has had economic benefits for consumers.

We intend to continue our investigation of the opportunities to further our energy and environmental goals through least-cost planning. Let me repeat that we believe those opportunities are real, and they are significant.

We do not believe, however, that legislation of the type embodied in Subtitle B of Title III of S. 324 is either necessary or appropriate at this time.

Thank you. I look forward to your questions.

[The prepared statement of Ms. Stuntz follows:]

STATEMENT OF

LINDA G. STUNTZ

DEPUTY UNDER SECRETARY

U.S. DEPARTMENT OF ENERGY

BEFORE THE

SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

ON

THE NATIONAL ENERGY POLICY ACT OF 1989 WITH SPECIFIC REFERENCE TO SUBTITLE B OF TITLE III OF S. 324

OCTOBER 26, 1989

Mr. Chairman and Members of the Committee, the Department of Energy (DOE) appreciates this opportunity to testify on the provisions relating to the Public Utility Regulatory Policies Act (PURPA) contained in Subtitle B of Title III of S. 324, the "National Energy Policy Act of 1989."

Title III of S. 324, the National Energy Policy Act of 1989, is directed at increasing energy efficiency. DOE provided detailed comments on S. 324 to the Committee on October 5. Today, I will review and expand on our comments pertinent to the Public Utility Regulatory Policies Act (PURPA) amendments proposed in Title III, Subtitle B.

Section 311 of S. 324 sets forth a federal "least cost planning" standard and requires that states consider the adoption of this standard within two years. Under the proposed standard, the rates charged by gas and electric utilities must be set "such that the implementation of least cost supply measures permits the utility to realize higher earnings than would be realized from the implementation of other supply measures." Section 311 also would require that currently unregulated electricity and natural gas distributors consider adopting this standard after providing public notice and hearing.

Section 312 of S. 324 would establish a new category of entity under PURPA, "qualifying conservation." The Federal Energy Regulatory Commission is to prescribe within one year after the date of enactment of this provision rules to "encourage the achievement of qualifying conservation." Among other things, such rules would require electric utilities to offer to purchase qualifying conservation from qualifying conservation entities.

Although the Department is fully supportive of innovative approaches to the encouragement of economic conservation, the proposed amendment to PURPA to establish a qualifying conservation entity raises serious issues. Forecasting and measurement difficulties substantially impede quantification of conservation actually produced. In the case of energy supplied by regular PURPA facilities, meters provide an accurate measure of output. In the case of conservation facilities, we do not yet have techniques capable of precise measurement of conservation achieved, particularly over time. Accordingly, we believe this section could impose significant implementation obstacles that could prevent achievement of the intended benefits.

The Department believes that energy conservation should be given the same consideration as our fuel resources. Accordingly, DOE is strongly committed to least cost utility planning (LCUP) or integrated resource planning. The Department of Energy's LCUP Program, mandated by Congress in the Department's fiscal year 1986 appropriation bill, supplies a wide range of ongoing research, information and development activities targeted at furthering LCUP in states throughout the country.

The DOE's LCUP program reflects the results of collaborative research assessments that have sought input from varied interest groups on the most appropriate research needs and priorities. DOE has prepared a report, entitled Least-Cost Utility Planning: Progress and Challenges, that identifies 20 LCUP topic areas for future work that were ranked by members of the utility, regulatory and research communities. The findings from this survey have been provided to appropriate organizations including the National Association of Regulatory Utility Commissioners (NARUC), the Edison Electric Institute (EEI) and others involved in utility regulatory planning processes.
This survey found that increasing the profitability of utility investment in demand-side management (DSM) clearly is seen as the number one priority for future analysis. Environmental issues and the treatment of environmental externalities were also emphasized, as well as market penetration rates for new technologies, uncertainty in least-cost planning, electricity

pricing as a resource, bidding for demand-side resources, and individual DSM technology assessment.

The current DOE LCUP program includes efforts in six areas: (1) integrated utility planning processes; (2) issues and strategies; (3) technology assessment and market penetration; (4) analytical tools; (5) technology transfer; and (6) program policy and planning. During FY 1989-90, seventeen research and technology transfer projects in these six program areas have been completed. Thirty-six projects are ongoing, either continued from FY 1988-89, or recently initiated. These projects have been carried out through cooperative efforts among utility companies, utility regulatory agencies, national laboratories, research organizations, local and state governments, and consumer/advocacy groups.

During this past year, NARUC has taken an increasingly active role in conducting research on, and fostering technology transfer for, least-cost utility planning. The NARUC least-cost planning program encompasses research activities on incentives for LCUP and on the role of LCUP in improving the nation's environmental quality. This program also promotes LCUP among state utility commissions through sponsorship of meetings and conferences, and has published two primers on least-cost utility planning processes and procedures. EEI and the Electric Power Research Institute (EPRI) have also become involved in the LCUP program and will continue to assist in defining issues and designing appropriate research projects related to the profitability and environmental research areas.

Also in FY 1989, the LCUP program released its second major competitive solicitation. This solicitation was targeted towards the particular least-cost planning problems faced by rural utilities in the northeastern United States. Eighteen proposals were received and evaluated, and nine of the offerors were selected for final award negotiations. Each of these projects supports building state level capabilities in the development of integrated resource planning processes that incorporate profitability and environmental concerns.
Several of the other LCUP projects that are playing a role include the Northeast Region Demand-Side Management Data Exchange (NORDAX), Review and Analysis of the Integrated Resource Planning Process in New York, Integrated Resource Planning Case Studies of Two Minnesota Utilities, and Michigan Regulatory Incentives Case Study for Electric Utilities.

When Title I of PURPA was enacted in 1978, relatively few states had actively considered some of the proposed Federal standards, such as the efficiency characteristics of automatic adjustment clauses and marginal cost pricing.

Support by state commissions for least-cost utility planning/integrated resource planning, however, is already widespread. EPRI estimates that state regulators and utilities in 43 states are involved at some level in least-cost planning. At least 17 States have functioning LCUP strategies, and eight States are beginning to implement this approach. Planners in 11 States are preparing demand side management rules for regulatory or legislative review and another seven states are evaluating the approach for possible application.

The working assumption in our DOE program is that the lead on LCUP activities most logically rests with state public utility commissions and with utilities. Our role in the process has been to facilitate the implementation of LCUP programs by means of a collaborative process that brings national energy objectives into play. These energy objectives include: improved international competitiveness; limiting greenhouse gas emissions; limiting emissions of acid rain precursors and gases that cause stratospheric ozone depletion; and improved energy security. Utilities and PUCs have implementation authority on these issues. We believe that the Department's role includes exercise of

National leadership, development of reliable data and analysis, identification of barriers to effective policy, and support and stimulus of action.

Overall, the Department agrees that least-cost utility planning and the development of a "level playing field" on which all energy sources, including demand-side resources, can compete is very important. However, we believe that any consideration of Federal standards in this area should be approached cautiously and in concert with state regulatory commissioners, utilities and others in a collaborative process. We also question application of this standard to otherwise unregulated distributors and sellers of natural gas and electricity.

As drafted, S. 324 raises important questions about how the standard would be implemented. For example, would gas or electricity marketers or brokers be required to hold public hearings to consider the Federal standard for nonregulated utilities? How would these nonregulated entities comply with the least cost-based requirements of the standard in a unregulated environment in which prices would be set by a multitude of market forces?

The proposed Federal standard contained in section 311 would require regulatory authorities to allow utilities to earn a higher return on investment in LCUP projects. Although some type of incentive may be appropriate in some cases, DOE is unaware of any analysis suggesting that the proposed standard contained in section 311 is necessary to encourage least cost planning. Absent a detailed analysis of individual regional resources and needs, customers may pay more than necessary for investments in demand-side management projects. State and local authorities clearly are in the best position to determine the proper rate treatment for supply projects of all types initiated by the utilities they regulate.

Conclusion

DOE believes that determined efforts to reduce and manage energy demand, through LCUP and other measures, play an important role in reducing CO_2 and other greenhouse gas emissions.

Conservation, fuel switching and renewable energy options should compete on an equal footing with traditional resource options. The collaborative LCUP efforts that we are witnessing at the state and regional level, fostered, in part, by DOE's LCUP program, are moving in the direction of such competition. Meanwhile utilities, utility regulators, and other interest groups have the freedom to experiment with alternative regulatory and incentive mechanisms that respond to national energy and environmental concerns in a manner that reflects the interests of their constituents. We support this collaborative process, and think that it is working. If federally legislated adjustments to this process must be considered, it should be done with due deference to the perspectives, concerns and needs of those currently working to enhance the role of demand-side resources in our Nation's energy mix. We are not convinced that Federal legislation of the type embodied in Subtitle B of Title III is necessary or appropriate at this time.

Senator WIRTH. Thank you very much.
Mr. Herod.

STATEMENT OF J. STEVE HEROD, DIRECTOR, OFFICE OF ELECTRIC POWER REGULATION, FEDERAL ENERGY REGULATORY COMMISSION

Mr. HEROD. Thank you, Mr. Chairman. I, too, appreciate the opportunity to appear before you today concerning S. 324. Let me observe that both my written testimony and my comments this morning represent staff views from the Commission. My testimony was not reviewed by the individual Commissioners, so I cannot indicate that the testimony represents an official Commission position.

I would like, in summarizing my comments, to focus in particular on sections 312 and 313 of the legislation which would amend the Federal Power Act to assert two new definitions:

One, for qualifying conservation, which is any reduction at any time in demand of electricity energy by customers of a utility, which reduction would not occur but for payments received by a qualifying conservation entity which the Commission determines by rule meets such requirements as the Commission may prescribe; and secondly, a definition for a qualifying conservation entity, a person who the Commission determines by rules meets such requirements as the Commission may again by rule prescribe is not primarily engaged in the generation or sale of electric power.

These definitions are patterned after existing Federal Power Act definitions of qualifying small power production facilities as implemented through PURPA and qualifying cogeneration facilities and would require the Commission to undertake a rulemaking to establish requirements for qualifying conservation and qualifying conservation entities.

Section 313 of S. 324 would amend the existing PURPA section 210 by adding conservation rules and the requirement that electric utilities purchase qualifying conservation. The Commission would be required to prescribe within one year after enactment such rules as it determines necessary to encourage achievement of qualifying conservation.

I would like to raise several issues; first, issues that relate to likely difficulties that we see in implementing such a law.

As a practical matter, measuring qualifying load reduction as required by the above definition will produce a number of complexities beyond those, the commissions and the states have had to grapple with under the existing qualifying facility program under PURPA. For example, to properly enforce payments to only real conservers, a baseline of consumption would have to be established from which the conservation can be measured.

This may involve an extremely large universe of potential applicants, since apparently all current electric consumers would be eligible. We have to date about 4,000 QFs on file at FERC as a result of the eight years of PURPA implementation. There are potentially millions of customers out there who could become the qualifying conservation entities under this statute.

The statute imposes an apparent need to verify that conservation would not occur but for the payments received under this program. This, in itself, would cause a very difficult issue in implementation.

It may be difficult to ensure that a demand reduction in one place will not be displaced by an offsetting increase elsewhere. Although a conservation entity may indeed reduce consumption in one area, the same entity or other entities may simultaneously increase consumption elsewhere to produce the same overall level of demand.

If totally new loads, new designs, new industrial facilities are eligible to bid, it raises the issue of whether or not there would become incentives to originally design these facilities in an inefficient manner in order to gain payments for a more efficient design which may have been the realistic commercial design in the first place.

There will need to be methods to assure that conservation, once sold under this program, is not later undone to come back into the system some years later.

Electricity conservation may be obtained by increasing the consumption of other energy inputs which would have to be a matter of rule as to whether or not such conservation should indeed qualify; again, a very complicated implementation problem.

There are also several issues related to pricing. These are issues to which we are very sensitive because the pricing that we have experienced under PURPA to date has been a very vexed issue, to say the least. Amended section 210 in this bill would preclude a rate to conservation entities that exceeds incremental cost to the electric utility of alternative energy. The term "incremental cost" would be defined very similar to the way avoided cost is defined under PURPA; in fact, identical, I believe.

We have learned from our experience with the existing program that there are many problems in implementing an administered pricing system. These issues are discussed in detail in a rulemaking that the Commission issued about 18 months ago dealing with the administrative determination of full avoided cost. There are many issues raised in that rulemaking. Those issues would again be present with us if we were to extend this program into conservation.

Additional issues would also be raised. Such issues as conservation programs changing demand patterns of customers, such that the residual services that they purchase would require repricing.

The length of a conservation purchase contract may be relatively short compared to the capacity planning lead times of generation assets, so there is a difficulty in matching the price you are paying for the conservation to the planning horizons that the utilities are pursuing in their generation plans.

There are other issues that are more familiar to the conservation programs involving no losers test and the problem of pricing conservation at marginal cost when the person practicing the conservation is also receiving the benefit of not having to pay for the kilowatt hour conserved, the so-called double payment problem.

These are all difficult issues. They are difficult issues in obtaining efficient conservation whether it is done through this PURPA type rulemaking, whether it is done through some other least cost approach, or whether it is done through competitive procurement. That is not to say that these problems cannot be solved, but the point I am trying to make is that to implement this program at the Federal level through PURPA would be very much more complicated than anything that we have seen under the existing program.

Again, I emphasize that none of this is to suggest that it is not appropriate to be seeking least cost approaches to procuring electrical supplies.

In response to the NOPR that I mentioned earlier, 11 State public utility commissions described efforts already under way in states to implement demandside programs. Some of these states encourage direct competition between supply and demand resources. Others have initiated a variety of programs ranging from accounting for conservation and demand forecasts used for planning to just simply requiring that the utilities use least cost techniques.

I think two broad conclusions can be drawn from the conclusions we have seen to date and the response of the industry to our NOPRs and to other programs such as Mr. Milhone's least cost utility planning program.

The first point I would make is that the electric utility industry in this country is emerging from a tumultuous period which has been focused on the difficult task of allocating the economic burdens of high cost generation facilities which in many cases were built well in advance of their need.

Now the industry is entering a new era in which attention will shift towards the challenge of meeting growing electric demand. As this new era emerges, the utilities and their regulators are showing a keen interest in meeting these needs in the most efficient way possible. This explains the growing interest in least cost planing, especially in regions where current supplies are the tightest.

As a part of this growing interest in the least cost electric power market, many states are also showing a strong interest in using competitive mechanisms to select least cost mix of options, including in some cases direct competition between supply and demandside options.

It is important to note that although PURPA made a very valuable contribution to this positive march of events, I agree completely with Senator Metzenbaum's characterization in that regard, however, the PURPA model itself is not the primarily vehicle being contemplated by most states and utilities for satisfying future needs.

We have learned from our experience with PURPA that its restrictions on which technologies get access to the market and its administratively determined pricing mechanisms cannot produce results as effective as a freely functioning market, which gives no technology, fuel, or application preferential access to the market.

Many states and utilities seem to be headed towards a more open and competitive model which allows all options, including demandside options, to compete freely. The result of this should be a truly least cost mix of supply and demandside alternatives.

Thank you.

[The prepared statement of Mr. Herod follows:]

FEDERAL ENERGY REGULATORY COMMISSION

Staff Testimony on S. 324
Amendments to the Public Utility Regulatory Policies Act of 1978 and the Federal Power Act

Mr. Chairman and Members of the Committee, my name is J. Steven Herod, Director of the Office of Electric Power Regulation, Federal Energy Regulatory Commission. I appreciate the opportunity to appear before you to testify on provisions contained in S. 324, the "National Energy Policy Act of 1989."

Sections 311, 312 and 313 of S. 324, would amend the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Federal Power Act to encourage least cost investment by regulated and non-regulated electric and gas utilities, and to require purchases of qualifying conservation by electric utilities. These comments present staff views on the effect of the proposed amendments on the Federal Energy Regulatory Commission's implementation of PURPA and the FPA and do not present the views of the Commission or any of its members.

Proposed Amendments

Section 311 of S. 324 would add two new sections to PURPA: Sections 114 and 115. These new sections would affect state regulatory authorities and non-regulated utilities. They would not directly affect FERC regulation.

The new Section 114 would establish a Federal standard under which "the rates permitted to be charged by a gas or electric utility shall be such that the implementation of least cost supply measures permits the utility to realize higher earnings than would be realized from the implementation of other supply measures." The provision states that implementation of least cost supply measures means actions including, but not limited to, conservation and other means of demand reduction, taken to provide adequate and reliable service to consumers at the lowest total cost to society, including costs incurred by the utility and its customers and environmental costs.

The new PURPA Section 114 would require each state regulatory authority, within two years of enactment, to provide public notice and hold a hearing on the above described Federal standard, with respect to each gas and electric utility under its ratemaking authority. Based on such a hearing, a state authority would be required to adopt and implement the standard _if_, and _to the extent_, such authority determines it is appropriate to do so and consistent with otherwise applicable state law. If the Federal standard is not adopted and implemented, the state authority would be required to state in writing the reasons why not, and make available such statement to the public.

For purposes of the new PURPA Section 114, gas and electric utilities would be defined as persons engaged in local distribution and sale of natural gas or electricity to any ultimate consumer, and over whom the state regulatory authority has ratemaking authority.

The new Section 115 of PURPA would impose the above described standards and requirements on non-regulated utilities.

The proposed PURPA Sections 114 and 115 are similar to the existing Sections 111-115 of PURPA, which required states and non-regulated utilities to consider Federal standards regarding cost of service, declining block rates, time-of-day rates, etc. They impose a requirement of a public hearing to consider adoption of a Federal standard, but they do not require the adoption of the standard. They would affect the FERC only indirectly, to the extent that the retail gas or electric utilities sell at wholesale and the cost-basis for supplying this market is affected by the new Federal standard.

Section 312 of S. 324 would amend the Federal Power Act to insert two new definitions:

(a) qualifying conservation -- any reduction at any time in the demand for electric energy by the customers of a utility, which reduction would not occur but for payments received by a qualifying conservation entity; and the Commission determines, by rule, meets such requirements as the Commission may prescribe.

(b) qualifying conservation entity -- a person who the Commission determines, by rule, meets such requirements as the Commission may, by rule, prescribe; is not primarily engaged in the generation or sale of electric power (other than electric power from cogeneration or small power production facilities).

These definitions are patterned after the existing FPA definitions of "qualifying small power production facility" and "qualifying cogenerating facility" and would require the Commission to undertake a rulemaking to establish requirements for qualifying conservation and qualifying conservation entities.

Section 313 of S. 324 would amend the existing PURPA Section 210 by adding conservation rules and a requirement that electric utilities purchase qualifying conservation. The Commission would be required to prescribe, within one year after enactment, such rules as it determines necessary to encourage achievement of qualifying conservation.

Implementation Issues

Promulgating and enforcing rules defining "qualifying conservation" would be more complex than our existing PURPA rules. As a practical matter, measuring qualifying load reduction, as required by the above definition, will produce a number of complexities beyond those the Commission and the states have had to grapple with under the existing qualifying facility program. For example:

-- To properly enforce payments to only "real" conservers, a baseline would have to be established from which the conservation can be measured. This may involve an extremely large universe of potential applicants, since apparently all current electric customers would be eligible. Currently, there are only about 4000 QFs, whereas there are potentially millions of customers that could apply for "QC" status.

-- The statute imposes an apparent need to verify that conservation would not occur "but for the payments received"; *i.e.*, the rules must be able to differentiate conservation that would have occurred in any event (natural responses to price increases, closing of uneconomical production lines, etc.), and conservation that would not have occurred but for this program.

- It may be difficult to ensure that a demand reduction in one place won't be displaced by an offsetting increase elsewhere. Although the conservation entity may indeed reduce consumption in one area, the same entity, or other entities, may simultaneously increase consumption to produce the same overall demand; *i.e.*, conservation at one point could result in increased consumption elsewhere.

- If completely new loads are eligible to bid from what their loads would otherwise be, inefficient original designs may be encouraged.

- Load data will probably have to be collected before and perhaps after QC certification. This may prove costly, especially for smaller customers with kilowatt-hour meters that do not record electric demand.

- Methods will need to be developed to ensure that the conserved load is not reimposed on the system. Purchasing utilities would probably have to assume the responsibility of making sure that conservation measures are legitimately sustained over the contract life.

-- Electricity may be conserved by increasing other non-electric energy inputs. We will have to decide if this is allowed and, if not, how to monitor and enforce this restriction.

-- The Commission may have to consider whether all kilowatts of load reduction should be counted as equivalent to capacity installed. An EPRI report (EM-3249, Project 1833), which deals with residential load management strategies, shows that for every 100 MW of peak reduction obtained through control, only 20.5 MW or less of capacity reduction can be counted for planning purposes. It is this "effective" capacity reduction that matters.

-- Many electric utilities have developed or are in the process of developing more aggressive conservation/demand side management programs. How should these existing utility conservation programs be handled after the QC program is established?

Pricing & Equity Issues

As under the existing PURPA law, QC rules would require electric utilities to offer to purchase qualifying conservation from qualifying conservation entities at rates that are in the public interest and not discriminatory against qualifying conservation entities. The amended section 210 would similarly preclude a rate to conservation entities that exceeds the incremental cost to the electric utility of alternative electric energy. The term "incremental cost" would be defined the same as under the existing PURPA law.

The Bill allows state regulatory authorities and non-regulated utilities the option of restricting the rate paid for qualifying conservation to an amount no greater than: (1) the incremental cost of alternative electric energy; or (2) the amount by which the incremental cost of alternative electric energy exceeds the price for the generation of electric energy paid by the customers whose demand for electric is reduced as a result of qualifying conservation.

We have learned from our experience with the existing QF program that there are many problems in implementing an administered pricing system. These issues are discussed in detail in the Commission's Notice of Proposed Rulemaking, Administrative Determination of Full Avoided Cost, Sales of Power to Qualifying Facilities, and Interconnection Facilities, Docket No. RM88-6-000, issued March 16, 1988. These include defining "avoided cost", acceptable methods for administratively determining avoided costs, contract terms, etc. Implementing a QC program raises the following additional questions:

-- Conservation programs may change customers' demand patterns and this may lead to changes in their use of other services provided by the utility. Backup and supplemental power contracts will need to be carefully written to spell out the utility's obligations to serve "previously conserved" load.

-- The length of the conservation purchase contract (in light of relatively free customer mobility) may be relatively short compared to capacity planning lead times and the life of generation assets. This may complicate the value of such capacity in the planning process compared to more conventional QF capacity.

-- The load characteristics of the conserved power and the shape of the remaining non-conserved load may be difficult to estimate without better customer metering, thus complicating both capacity planning and the design of proper backup or supplemental power rates.

-- The Commission will have to face the question of inequities, such as to customers who have previously conserved (taking measures similar to the measures that will now qualify for payment). Will such customers be required to pick up the incremental cost of payments to the new "qualifying conservation entities"?

General Comments

To the extent that additional demand-side management/ conservation can be achieved, it will further help to reduce or delay future supply needs while providing environmental benefits and more efficient use of resources. The S. 324 amendments attempt to foster efficient conservation and demand side management by:

(1) encouraging utility conservation/DSM investments by financial incentives under traditional rate regulation; and

(2) requiring utilities to "purchase" conservation/demand-side management options that meet certain Federal standards.

However, it is important to recognize that many states have implemented or are seriously considering competitive procurement programs to satisfy future electric power needs in a "least cost" manner. The FERC, in its Notice of Proposed Rulemaking on competitive bidding, Docket No. RM88-5, issued March 16, 1988, requested public comment on how demand-side options should be considered in bidding, i.e., whether they should compete directly or whether there are other ways to take them into account. The Commission pointed out that the objective of a bidding program should be to promote efficiency and, therefore, states might want to consider demand-side alternatives to capacity expansion.

In response to the NOPR request, 11 state public utility commissions described efforts already underway in these states to implement demand-side programs. Some of these states encourage direct competition between supply and demand-side resources. Others have initiated a variety of programs ranging from accounting for conservation in demand forecasts used for planning purposes, to requiring that utilities use least-cost resources.

I think two broad conclusions can be drawn from this experience:

(1) The electric power industry in this country is emerging from a tumultuous period which has been focused on the difficult task of allocating the economic burdens of high cost

generating facilities which were built well in advance of their need. Now the industry is entering a new era in which attention will shift toward the challenge of meeting growing electricity demand. As this new era emerges, utilities and their regulators are showing a keen interest in meeting these needs in the most efficient way possible. This explains the growing interest in "least cost planning," especially in regions where current power supplies are tight.

(2) As part of this growing interest in a "least cost" electric power market, many states are also showing a strong interest in using competitive mechanisms to select the least cost mix of options available to meet future power needs, including in some cases direct competition between supply and DSM options.

It is important to note that although it made a valuable contribution to this positive march of events, the PURPA model itself is not the primary vehicle being contemplated by most states and utilities for satisfying future market needs. We have learned from our experience with PURPA that its restrictions on which technologies get access to the market and its administratively determined pricing mechanism cannot produce results as effectively as a freely functioning market which gives no technology or fuel preferential access to the market.

Many states and utilities seem to be headed toward a more open and competitive model which allows all options to compete freely. The result should be a truly least cost mix of supply side and demand side alternatives.

Senator WIRTH. Thank you very much. It seems now everybody is pretty much in agreement, in the late 1980s, that we want to pursue a least-cost approach. I mean, both of you have said that. And so we are beyond any ideological discussions or economic discussions about that. The question is now one of implementation.

I gather that the questions that the two of you have relates to the implementation of the conservation provisions as found in the legislation.

Let me ask you, first of all, if you would be willing to get back to us—and by the way, Senator Metzenbaum has a number of questions for the record, which he will be submitting, and we will leave the record open.

Could you get back to us (and maybe this is a useful way to start) with your suggestions as to how we ought to change the legislation were we to follow one of two tracks.

There is one track that says that we ought to, at the federal level require this, and leave the implementation up to you, correct?

There is another track which I gather you are suggesting, Ms. Stuntz, that we should not have this provision as a federal requirement, but should more permissibly leave it to the states? I mean those are the two models that we are looking at.

Now, rather than saying one or the other at this point, let us talk about them sort of in tandem here, because there are pluses and minuses with each model.

And what I would like to get us to, if we might, are suggestions from FERC and from DOE that, were one to follow one model, what language should be changed in the bill; were you to follow the other model, what language should be changed in the bill?

So I am going to ask you if you can get back to us with your suggestions for change for both models, rather than saying throw one out or throw the other out?

[The information referred to follows:]

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Department of Energy
Washington, DC 20585

January 5, 1990

RECEIVED JAN 05 1990

The Honorable J. Bennett Johnston
Chairman, Committee on Energy and
Natural Resources
United States Senate
Washington, DC 20510

Dear Mr. Chairman:

I appreciated the opportunity to testify before the Senate Energy and Natural Resources Committee on October 26, 1989, on the "Natural Energy Policy Act of 1989."

I am happy to provide for the record a response to questions raised by Senator Timothy Wirth during the hearing. I trust that the enclosed testimony insert is responsive to the Senator's request.

If I may be of further assistance, please do not hesitate to contact me.

Sincerely,

Linda G. Stuntz
Linda G. Stuntz
Deputy Under Secretary
Policy, Planning and Analysis

Enclosure

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COMMITTEE INSERT ON S. 324, TITLE III

REGARDING AMENDMENTS TO PURPA

Question from Senator Wirth: While recognizing that the Department of Energy recommended in its testimony that no Federal legislation on this issue is needed at this time, Senator Wirth requested that the Department provide suggestions for improving Title III, Subsection B within the context of a strong Federal model and an alternative model providing maximum flexibility to the States.

Answer: As Senator Wirth recognized, the Department does not recommend legislation on this issue at this time. This answer responds to the Senator's request that DOE offer suggestions for improving the proposed legislation. The issue is whether the Federal government should require the States to consider a particular least-cost utility planning (LCUP) standard and provide for utility purchases of qualifying conservation. In addressing this issue, the advantages and disadvantages of both a strong Federal model and a model leaving maximum flexibility to individual States are presented.

A Strong Federal Model

The primary advantages of a strong Federal model to promote LCUP activities would be: (1) uniformity; each State would consider the same standard; (2) universality; all States would be required to consider the standard, and (3) simultaneity; all states would engage in the consideration process at the same time.

LCUP programs must be tailored to local circumstances. Although the LCUP Standard proposed in S. 324 is flexible, the question is, why require consideration of a Federal standard if uniformity is not appropriate? As I noted in my testimony, the great majority of States already are moving forward with some form of LCUP. Given the rapid progress being made, the merits of universal and simultaneous consideration of a Federal standard do not appear compelling.

In summary, the benefits that a strong Federal model might provide either are not apparent or are relatively modest in the case of LCUP.

The Maximum Flexibility Model

The alternative model, in which the individual States have maximum flexibility to fashion LCUP strategies and programs to fit local circumstances, has already taken hold. Much progress has been made through innovation and experimentation by the States. Some of the projects supported by DOE, which illustrate the extent and diversity of this innovation, include:

- Development of a nationwide on-line computer network and database to promote the cross fertilization of ideas among States regarding LCUP policies, and to serve as a national clearinghouse or reference source for those States interested in researching LCUP developments occurring elsewhere.

- A project to provide reliable, objective information to staff members of State utility regulatory agencies on the conceptual and methodological issues underlying least-cost energy services planning, and to assist them in more effective use of available modeling and analysis tools.

- A long-term plan to stimulate establishment and maintenance of an effective, non-duplicative, multi-participant information system network (including document listings, keywords and abstracts, and selected quantitative data) that will be accessible by utilities, State agencies, and researchers for purposes of least-cost utility planning and policy-making.

- The Northeast Regional Demand Side management Data Exchange, known widely as NORDAX, is operated by a group of 19 utilities which together account for about 11% of U.S. installed generating capacity. NORDAX was formed to establish a data base containing data from actual LCUP experience, and to share that data with other States and utilities considering LCUP programs.

These programs characterize current LCUP activities. They demonstrate how much more broadly information on these complex regulatory issues is being shared today than it was when PURPA was passed a decade ago. As superior LCUP implementation strategies are developed, the Department of Energy should continue to encourage their implementation, and make the results of these strategies available to utilities and regulators across the country.

Having describes the "strong federal" and "maximum flexibility" models, let me evaluate Title III, Subsection B of S. 324. Specifically, Subsection B requires that: (1) State public utility commissions (PUCs) consider implementation of a Federal standard for regulated natural gas and electric utilities which would require utilities to implement LCUP activities, including an incentive return on LCUP investments; (2) non-regulated electric and natural gas utilities consider implementation of a similar Federal standard regarding LCUP; and (3) the FERC implement procedures, after consultation with State authorities and others, requiring electric utilities to purchase "qualifying conservation" from "qualifying conservation entities".

The Federal Standard

The Section 311 approach, which requires State PUCs to consider a Federal LCUP standard and implement it only if appropriate for their individual circumstances, appears to be consistent with the maximum flexibility model. However, this Federal standard should be based on the premises that formulating and implementing LCUP programs must be done by local regulatory authorities and utilities, and that LCUP investments should be undertaken only if they represent the least-cost option.

The provision of Section 311 requiring a higher return on LCUP investments than on other utility investments violates both of these premises and represents an unnecessary infringement on State regulatory authority. I suggest that this provision be changed to require State PUCs to consider whether or not current regulatory mechanisms create a bias against LCUP activities and, if so, to adopt measures to correct this bias. This approach would provide a Federal impetus to States to address the issue of regulatory disincentives to utility demand-side investments, while providing the necessary flexibility to deal with a problem that requires a case-by-case approach.

In addition, I suggest that the requirement to adopt the Federal LCUP standard for natural gas utilities be eliminated. LCUP programs for electric utilities are fairly well along in development. Those for gas utilities are only beginning. It is simply too early to initiate a Federal standard for gas utility LCUP programs until we know more about what would work and what might have unintended adverse consequences for natural gas producers, marketers, pipelines, utilities, or consumers. Federal activity in this area should concentrate on research, analysis, and perhaps some "test" cases.

Non-regulated Gas and Electric Utilities

Section 311 of the bill also would require non-regulated gas and electric utilities to consider implementing the Federal LCUP standard. DOE believes that this provision should be eliminated because it would be very difficult to implement, and would have marginal benefits. Many non-regulated electric utilities (i.e., cooperative and municipal systems) currently are involved in LCUP programs. For example, the Bonneville Power Administration (BPA) and its local cooperative distribution utilities have instituted an energy conservation program designed to significantly reduce growth in electricity consumption throughout the Pacific Northwest region. We believe that these unregulated utilities, many of which are very small and do not generate electricity, need not be required to consider a Federal LCUP standard.

As stated above, LCUP programs for natural gas utilities are only in the initial stages of development. Requiring non-regulated natural gas "utilities" to consider a Federal LCUP standard would be premature and could impose burdens on natural gas pipelines and marketers unless the gas "utilities" included in the program are more limited than the current PURPA definition of "utility" provides.

Qualifying Conservation Entities

Section 313 of the bill would require FERC to establish rules and regulations requiring electric utilities to purchase "qualifying conservation" from "qualifying conservation entities" if such conservation would not otherwise take place. These provisions are in conflict with the maximum flexibility approach and are opposed by DOE. Moreover, DOE agrees with FERC's assessment that these provisions would be very difficult to implement and would produce uncertain results. States like Maine and Massachusetts are allowing conservation to compete against generation in auctions to satisfy electricity needs. This competition serves the objectives of Section 313 without the problems associated with PURPA's administered pricing system. Accordingly, DOE believes that, if any Federal mandate is considered appropriate, the approach taken by Section 311, which permits a flexible response to LCUP, would provide the proper Federal response to this issue.

FERC's Response

RESPONSE TO QUESTION FOR THE RECORD FROM SENATOR WIRTH

Question: Please provide suggestions as to how the legislation could be changed under the assumption that it is appropriate for the federal government to require implementation of least cost measures including conservation and demand management.

Answer: Under the assumption that it is appropriate to Federally legislate a requirement that the states implement some form of least cost measures, FERC staff would not recommend using a mechanism designed to replicate the program for qualifying facilities under PURPA. There are two primary reasons:

1. Although the PURPA model has succeeded in opening up electricity markets to non-traditional suppliers, this market access has been restricted to a limited class of potential suppliers (cogenerators and small power producers). The proposed legislation would remove these restrictions to market access but only to a limited part of the remaining spectrum of potential market participants, namely qualifying conservation entities. Many other alternatives, including clean-coal technologies, gas-fired combined cycle, nuclear and large hydro electric facilities would not be eligible for market access on the same terms as "QFs" and now "QCs" under the proposed legislation. Without these alternatives being allowed to compete in the marketplace under comparable terms and conditions, it will be difficult to assess if the successful "QFs" and "QCs" are really part of a least-cost mix.
2. Due to the restricted market access under the PURPA model, it has been necessary to devise an administered pricing system which is intended to simulate market prices by relying on the "avoided cost" concept. Although conceptually appropriate, the implementation of this administered pricing system has frequently failed to provide the correct prices and has thus resulted in unintended subsidies to QFs in some cases, and prices below fair market in others.

These problems with the PURPA model do not suggest a retreat from an effort to open electric power markets to competition in order to assure a least-cost mix of supply-side and demand-side options. Instead, the experience with the PURPA model suggests the potential for opening electricity markets to an unlimited array of competitors who compete on a fair basis.

In order to create this open market, any Federal legislation should be targeted at eliminating barriers to entry for all potential supply and demand-side options. To realize fully the benefits to consumers that will result from such market conditions, two areas may require attention: the Public Utility

Holding Company Act (PUHCA) and transmission access. Legislation has already been introduced by Senator Johnston to amend PUHCA in a manner which addresses the entry problems PUHCA may pose for a competitive market.

With respect to transmission access, the recent Transmission Task Force Report to the Commission identified the importance of transmission to a competitive wholesale market. It concluded, however, that the emerging incentives of the industry and existing FERC authorities may be currently sufficient to assure that necessary transmission service will be made available in a timely and fair manner without legislative reform.

Beyond the PUHCA and transmission issues, there remains the concern that states and utilities will not choose to include demand-side alternatives in future planning activities or in future competitive procurements. This concern, however, is not substantiated by the emerging evidence as an increasing number of states and utilities confront the need for additional capacity. On the contrary it appears that, least cost planning is emerging as a central focus for states and utilities which are confronting future power needs. Federal legislation targeted at requiring least cost planning may serve to strengthen the resolve of the states, but it may also create some unintended consequences from the states similar to those after PURPA was enacted ten years ago. This potential is made even more likely in this instance since the states are already showing strong predilections toward least cost concepts.

Senator WIRTH. So with that as background, saying we are going to try to look at this in tandem and to sort our way through, let me back up and see, first of all, if the historic analogy is correct.

A lot of the same arguments that are being made against building conservation into the legislation at the federal level were made at the time that we passed PURPA.

I was in the House on the House Energy Committee at that time, Senator McClure will remember this on the Senate Energy Committee at the time, when we passed PURPA there were two arguments.

One was that you would not get very much out of this, do not bother to do it.

The second was that this should not be done at the federal level; we should leave it to the states to implement; it is much too complicated to do.

Those are the arguments that were made in 1977 and early 1978, as we were debating, or at least were made on the House side.

We have found out that, one, there was a great surprise as to how much energy came out of that. And second, I think we have found out, and you may correct me on this, that the implementation problems, while complex, as you point out, Mr. Herod, have in fact, for the most part, been able to be worked out as the states have moved into this.

It was required at the federal level; we said much would not come out; it is too complicated to do, but it has worked pretty well. I think generally there is agreement that it has worked pretty well.

So that is the argument, to say if that worked, let us draw the parallel or use that example of what was successful 10 years ago, draw on that, and what do we learn from that about what we ought to be doing in this case, for requiring it at the federal level?

We all know that some states are more progressive than others, some are pushing harder than others, some have energy problems that are more intense than others, so consequently they are going to do it anyway, but others are not, so we ought to be pushing them, as we did in PURPA.

So that is the other model.

The first model of just leaving it to states is the one that both of you, I think, are suggesting in your testimony.

So I would like you, if you might, reflect upon that, is that correct, and might we go ahead looking at what changes might be made if we follow the federal model, which is more in the legislation; or the state model, which I understand the two of you are suggesting?

I am leaving this open for whatever comments you might like to make on it.

Ms. STUNTZ. I will venture a first crack at that, and then defer to Steve. I think we have learned a lot from PURPA, and we have those lessons clearly in mind. I think you did not hear us say in our testimony that you will not get conservation, or very much, if you do this. I think if you tell the utilities that this is how you can make more money, that is what they are going to do.

Now, we do have questions about whether this would truly be least-cost, and whether we truly know enough now to do it in the way that would make sense.

Another important difference, I think there were some significant lessons that we have learned from PURPA about the government's ability to set a pricing standard.

If you talked to folks in California or you talked to folks in Texas, they will tell you that it was set in the wrong place for a long time, and therefore they have inefficiency, more than they should have, and utility customers are paying more than they should pay for the economical mix of resources.

Another key difference is that without PURPA, States could not have exempted qualifying facilities from federal regulation. And that is a thing that PURPA did that really freed up that market.

And I do not think that is the situation again that you have here.

So we are not trying to give you the same old arguments. I think we have learned some things from PURPA, too. And I think we need to make sure we build on that and do the things that were good about PURPA, but not do the things that were not good.

And the one other distinction I think that exists, as I tried to point out in my written testimony, many of the proposed standards that PURPA brought to the fore and that, as you point out, were not terribly popular at the time, really had not been very much considered by the States then; not nearly the level of consideration, the level of implementation that has already occurred in least-cost utility planning programs.

So I do not think it is a situation where if there is not a serious federal prod right now, this is not going to get done.

Senator WIRTH. I would of course argue the other way, too, that of course because people are more up to speed on this sort of thing, we have got a lot more experience. And I could argue the sense of urgency for a federal level as well.

But, anyway, that is very useful.

Mr. HEROD. To echo a couple of points that Linda makes. It is very different, on the one hand, to be purchasing supply, as in the QF program, from purchasing conservation under this proposed legislation. A supply purchase is a wholesale trade. In most parts of the country it is a wholesale trade in interstate commerce. It would require federal oversight.

So there had to be a law that dealt with how those trades would be regulated, because they would be FERC jurisdictional.

In this case, where we are dealing with conservation at the retail end of the business, there is no such requirement. The transactions in the main will not be subject to any federal regulation. The regulation would be at the state level.

So there is a basic difference in buying power in wholesale trade versus buying conservation in retail trade, which is a state jurisdictional issue. So the regulatory pedigree is very different on the two types of transactions.

I think also there was a clear and strong argument in 1977–1978 that the industry was not likely to be forthcoming in purchasing QF power. I think that there was a lot of clear evidence that the industry was not predisposed toward buying power from cogenerators and small power producers.

Clearly, PURPA broke down those barriers. They have purchased, because there is a requirement to purchase under PURPA. And I think that fixed a market imperfection, in effect.

I think that there is a question as to whether the utilities and the states are not predisposed today to pursue least-cost options? And I think that there is a lot of evidence out there today that suggests that the industry is very much inclined to pursue these, in large part because the states themselves are very much inclined to cause the industry to pursue conservation.

And third, PURPA working well. I would agree with that in the main. PURPA has taught us a lot of very good lessons, it has opened up the market, it has produced efficiency, but it has also produced some inefficiency. And a large part of the inefficiency that has been produced is by the fact that the PURPA model itself is an administered pricing model.

The prices are set by bureaucrats trying to figure out what the price ought to be, posting it, and letting anyone come and take that price that chooses to.

That pricing mechanism, we have learned in some cases, does not work well at all. In some cases that price has been set way too high and we have had, in effect, gold rushes of cogeneration and small power production that actually will end up burdening consumers with very high costs.

So even though the PURPA model succeeded in bringing some new supplies to market, and much of that supply was very efficient and welcome, some of that supply was, in effect, subsidized by the administered pricing system that did not work well.

I think one of the lessons we have learned in PURPA is that you can go beyond an administered price system and use more market discipline in setting the price, so that you can be more confident that you are not subsidizing or shortchanging people who want to get access to the market.

And that is why I think in a lot of states you are seeing people move towards competitive mechanisms, which are not the PURPA model. PURPA is not a competitive model, simply because the pricing mechanism itself is an administered pricing system; it is not a competitive pricing system.

And a lot of states are moving beyond that administered pricing system into a competitive model, to make sure that the price is right and we get the most efficient and the least-cost options brought to the market.

Senator McClure. Could I ask a question right there, because I think it ties in with that?

Is it possible to identify the amount of increased energy demand there will be in a system, just as we traditionally did in trying to meet future need by building for future need, the supply, and identify that increment of additional demand that must be satisfied by either supply or conservation, and put out for bid conservation measures which might help alleviate that demand and allow the best bidders to get the contracts?

Mr. Herod. I think the answer is yes. In fact, it has been done.

Senator McClure. And is that not a better mechanism than the administered pricing that you find troublesome?

Mr. Herod. I would argue yes, because you can have more confidence that the price that is being set is a price that is appropriate and that the winners of that competitive solicitation are indeed the most efficient options, whether they are supply-side oriented or demand-side oriented.

Senator McClure. It also would avoid one of the other problems we have seen with PURPA, and that is it would avoid an excess of capacity being contracted. PURPA has stimulated some of that.

Utilities have been forced to buy, under PURPA, supplies which they did not need. And there ought to be a mechanism by which we could avoid buying conservation which was not needed to meet demand.

That would be inefficient from the standpoint of substituting for existing supply a conservation, and therefore rendering uneconomic the investment in supply. It might cost the system more; it might cost the consumers more.

Mr. Herod. Indeed. I think it is very important to figure out how to get the price right. I think what we have learned from PURPA is that you can use the market to set the price, rather than setting it administratively.

I just would observe that we have made pricing errors by pricing too high and, in effect, subsidizing QFs under PURPA. I am sure that there are also areas out there where we have priced too low and caused some good efficient QFs not to get to market because they have not seen the right price signal. So there have been errors on both sides, I think.

Senator Wirth. Just as a comment on this, if I might, just to close this out, and then I will go to Senator McClure.

Excuse me, Don, did you have something?

Senator Nickles. I wanted to follow up on the same, but go ahead.

Senator Wirth. Again, for the purposes of getting a response back from you on your comment specifically on the legislation.

Clearly, the legislation is written to give FERC a great deal of discretion, as you note in the bill. And you raise a number of interesting implementation questions, which are, do we want to try to take all of them on?

You know, you talked earlier about the question of the population of qualifiers. I mean, that could be enormous, as you point out, it could be a major problem, and we could avoid that through the way in which FERC were to write its regulations.

I mean you can make this thing, from your perspective, as complicated as you want, or, if you were to follow the model of a federal prod, all right, which is the first model we were talking about, you set it up in such a way that FERC writes in a broad, regulatory brush, and then leaves it up to the states to implement. All right?

So I would like you, if you might, to again come back with the two kind of models.

I would also like, Ms. Stuntz, to point out to you that there are two parts of this that are important and we ought to separate those out.

The first one, which has not been, I think, controversial and that people have not disagreed with is the notion of removing existing disincentives for utilities to pursue demand-side management.

You know that is largely hortatory, but requires state utility commissions to have a hearing and to focus on that issue. I do not think there is disagreement on that front.

The place where there has been the greatest controversy or the greatest discussion is the notion of creating a federal, third-party right. And that is the more difficult one I think, and I want to make sure that in your comments you might separate those two out.

Anyway, there are two models. If you could get back to us, I think that that would be a helpful thing to do.

Senator McClure.

Senator McClure. Thank you, Mr. Chairman. I will be brief. I believe we have a vote coming up and I will leave time for my colleagues.

I want to state for the record what I have stated before, and I want to reiterate today, PURPA is not an unmixed blessing. PURPA has caused some problems as well as created some benefits. And I think every observer recognizes that there is some of both.

There are different evaluations as to whether the benefits outweigh the detriments under that act. I am not getting into that today, except just to lay out for the record at least the observation that PURPA is not an unqualified success and therefore should not simply be eagerly embraced as the pattern by which we get further unqualified successes.

I think your testimony and your comments following your testimony have outlined some of that area, and some of those areas have been outlined before this committee in hearings before, starting shortly after PURPA was implemented and continuing over the years.

I do have two or three rather general questions. Mr. Herod. On page seven of your testimony, the middle of the page, you are talking about effective capacity reduction accounts.

And I would gather from that, you would rather see us talk in terms of effective capacity reduction, rather than load reduction without the term "effective." Is there a way to define that? Or could you submit to us language that would define that in a way that you think would be more accurate?

Mr. Herod. Yes, sir.

[The information referred to follows:]

RESPONSE TO QUESTION FOR THE RECORD FROM SENATOR McCLURE

Question: Is there a way to define "effective capacity reduction" to eliminate the concerns raised in the FERC testimony pertaining to paying for conservation or demand management?

Answer: Yes. The value of a kwh saved is a function of many factors including in particular the timing and certainty of the conservation. A kwh conserved at the time of overall system peak demand will have a higher value than a kwh saved at the time of lesser system demand. A kwh saved predictably over the entire year is more valuable than a kwh saved on an unpredictable pattern for part of the year.

The issue here pertains to the appropriate capacity credit to give to any particular conservation measure. The capacity credit should be a function of the impact the measure has on the capacity needs of the system. A conservation measure which guarantees a year-round reduction in demand over the entire planning horizon of the utility should get full credit for the capacity avoided. A conservation measure which is less certain, or which is available for a smaller part of the year, or for only a part of the planning horizon of the utility, should be appropriately discounted to reflect its true value in terms of displaced capacity in the system plan.

Senator McClure. On page nine, in the middle of the page you are talking about the customer mobility and the fact that utility planning parameters are over a longer period of time than the customer contracts. Is it not possible to make those more nearly coextensive simply by the administrative action of the length of the contract?

Mr. Herod. Yes, it is, if you can ensure enforcement and fulfillment of the contract. It is a consumption pattern that you are contracting for. And so you are contracting for a behavior pattern in many cases.

Senator McClure. And some load could very easily go out of existence?

Mr. Herod. That is correct.

Senator McClure. If a business files a contract and then ceases to exist. But much of that load, even though the customer might be mobile, the load is not.

Mr. Herod. Well, it depends. If someone shuts down a facility or shuts down a line and opens up another line somewhere else.

Senator McClure. Or if the person who owns a home, that home burns down and is not replaced, that would be another example of the impermanence of the load reduction.

Mr. Herod. That is correct.

Senator McClure. But in general, are there not ways to tie the load conservation to a general pattern of consumption so that the lack of permanency is more an aberration than a pattern?

Mr. Herod. It is hard for me to generalize simply because there is so many different ways to conserve energy, and some of them are fixed patterns and some of them are not fixed patterns.

Senator McClure. I understand that.

On the top of page 10 you talk about the inequity, or perhaps possible inequity, of asking some customers, who have already applied conservation measures, to help pay the cost to others to apply conservation or load reduction measures.

Now is that not implicit in the entire scheme?

The scheme is really the benefit to a region or the nation as a whole, but to the region, with respect to load reduction. And everybody in that region benefits equally from load reduction. If it is to be cost effective, even though they have paid for their own conservation, it does not cost them anything to pay now because otherwise they would pay for more generation capacity.

Is that not the idea on which this is all based?

Mr. Herod. Well, it depends. The proposed legislation lays out two ways to pay for the conservation, one, where you pay the full incremental costs; and the other one where you pay the difference between the incremental cost and the charged rates, or the embedded costs.

Senator McClure. But it is based upon the theory that if you do not pay it, that way you will pay it the other way?

Mr. Herod. If you will pay the differential you can obviate a lot of these equity problems, if you just pay the difference between marginal costs and embedded costs. But if you pay a conserver the full marginal cost, he is also receiving the benefits of not paying the price for the electricity which he conserves.

Senator McClure. But it is based on the idea that if you do not pay for the conservation costs, you are going to pay for capacity costs?

Mr. Herod. As I understand it, the legislation is meant to be based on making the consumer indifferent to the conservation being purchased.

Senator McClure. That is right. And if, indeed, the consumer is indifferent, then the comment you make on the top of page 10 really does not have any applications?

Mr. Herod. If it is implemented in a way to make the consumer indifferent, that is correct, yes.

Senator McClure. Thank you very much.

Senator Wirth. Senator Burns.

Senator Burns. I will defer.

Senator Wirth. Senator Nickles.

Senator Nickles. Mr. Chairman, thank you very much.

I am looking at the legislation as proposed and as talked about. The least-cost investment mentions gas utility and electric utility, it mentions implementation of least-cost supply measures. That means actions including conservation taken to provide adequate and reliable service to consumers with incurrence of lowest total cost to society, such costs to include costs incurred by the utility and its customers and environmental costs.

Now I do not know exactly what that means. But I am trying to figure out what it means in the gas industry. I have a lot of concepts, in the utility and electric areas. I am on page 27 of the bill. What would that mean as far as gas?

Are we going to be mandating these federal standards to basically mandate least-cost purchases of gas, therefore mandate no gas contracts higher than the least cost, therefore the lowest cost gas prices that happen to be out, and we have gas prices all around?

We are going to mandate that for gas? Am I misinterpreting that or is that potentially there?

Ms. Stuntz. I believe that potential is there. I think there are some real questions about turning PURPA, as I tried to say earlier, from a seller's right to have someone buy their power, to a regulatory program, which is really what this proposal is.

And it may be that it is mostly hortatory and they hold a hearing and say well, we are being as prudent as we can. It may even be rolled into a prudence-type proceeding.

But I would be concerned that if there is someone who thinks that gas utilities are not operating as efficiently as they could, that they are not doing enough weatherization or investing enough in consumer efficiency measures, and instead just buying more gas, that there could be some controversy as a result of that. And I think it is important that there would be a clarification, I would suggest, of what are you trying to accomplish here for gas utilities?

If it is a least-cost purchasing strategy, that is one thing; if it is an efficient operation strategy, that may be another thing; and if it is trying to make sure you pay attention to your consumer side of your business as well as the least-cost purchasing side, that may be another thing.

And I think it is complicated when applied not only to gas utilities, but, as I said earlier, I am a little concerned with all the new entities we have in the gas business now, marketers and so forth, to the extent that a marketer sold directly to a consumer, it is not really a utility, but I would be concerned that this could apply to it somehow, if you look strictly at the definitions.

And again, I would think that would be something to clarify, in terms of non-regulated utilities, who are you really trying to get at?

Are you trying to get at only co-ops or municipals or things that are obviously utilities, but not regulated by the States? Or are you really trying to get at—I mean there are a lot of end-users that are buying not now from gas utilities, and so how would this affect them, and what would a least-cost planning obligation mean for them?

I do not really know the answers to those questions.

Senator NICKLES. You mentioned, if you just look at page 26 on line 19, it says that they shall adopt and implement the standards. So, therefore it is mandatory that these standards would be enacted.

Would you agree with me, I would think most utilities and most gas utilities, as well as electric utilities, would have enough incentive on their own to be enacting least-cost measures for their customers and for that utility without having the federal mandate.

Would you agree with that? Because it says shall implement, it does not say may implement.

Ms. STUNTZ. Well, I think, as I read it further on, if the State decides, for whatever reason, after a notice and hearing, that it does not need to do this under the usual PURPA model, they do not have to. And that has been the case with PURPA before.

There have been a number of proposed standards that have not been adopted, but they do have to consider it; they have to consider it within two years under the legislation. And it has to be a decision made on the record—supported by evidence.

So, I think, presumably if a state said we have got a darn good least-cost planning program of our own, where we are doing this in a competitive way, and we think this is going to accomplish what you want to accomplish without this particular standard, we are going to go our own way, as I read it, they could do that.

Senator WIRTH. If the Senator would yield.

Senator NICKLES. I would be happy to.

Senator WIRTH. In drafting the legislation, there was a major debate whether gas utilities should be involved. There were some who felt that we ought to try it and see if there were others who felt that we ought to leave it out or as you are suggesting, just leave it to distribution utilities. That distinction was there.

And we have been trying, in the revising of the legislation, and we would certainly hope you could get together with our staff on that front, and Don, make sure we get the benefit of your input on that, because you put your finger on an issue that was difficult going in, and remains difficult right now.

Senator NICKLES. Let me give you some more input. [Laughter.]

Reading a little bit further, I am thinking of a major purchaser in my state and many states, which is Intrastate Gas Pipelines. And I would think that that would be qualifying.

And I am really concerned, Tim, that what we are doing, if we are not careful, is we are going to be mandating to those local regulatory agencies, in my state it would be the Oklahoma Corporation Commission, this least-cost method, which would be mandating, basically, that they purchase spot gas.

And you have a volatile market. Spot gas, as you know, many times chases down, in some cases, and then every once in a while, you have a blurb up or a chase up. I do not want to have a situation where we are making that kind of mandate. I really do not want FERC to write regs to where that might be the result.

I have no desire. As a matter of fact, we just spent several years, about 35, trying to deregulate natural gas, and we were successful. I do not want to have some other back door regulatory approach that is going to mandate to the states "a least-cost method" that has the net effect of either, one, regulating gas prices or, two, driving gas prices down to somebody's perceived level of least cost or, three, that would really disrupt or continue to regulate a market that we have been trying to get in a deregulated market. That would be a serious mistake.

I do not really think the Senator from Colorado wants to do that either.

Senator WIRTH. No, the Senator and I have worked on these issues together for a long period of time. I think that the question that you raise is an interesting one, but a bit of, I would say, maybe the word is too harsh, a perverse interpretation or negative interpretation of what we are trying to do.

In looking at least cost, you are looking at long-term planning and long-term costing, and that would get you right out of any kind of spot market interpretation.

But, let me say, we ought to look back at the legislation and make sure that we make all of that clear. The whole business of including gas utilities in this was one that had been strongly suggested by some that we ought to try to do, and that is the purpose of drafting a bill and putting it out there and getting comment on it.

I think that we are in the process of redrafting, and we would like to work with you and your staff and so on as we are reworking all of this, because it does raise some very interesting questions, some of which Ms. Stuntz reflects and some of which you do. And we are aware of a lot of these, and there may be others as well.

Senator BURNS. Would the Senator yield just for a question?

I just want to throw out an application thing here. I am sort of confused. Now, we built a new public facility in Billings, Montana. And rather than going to Montana-Dakota Utilities—the only way I know how to clarify something is to draw an illustration, okay, in the real world. We do not live in that world too much.

And instead of contracting with Montana-Dakota Utilities in Billings, Montana, for energy on two new public facilities in Billings, we contracted with some private operators that have gas wells in the Williston Basin. And we made the deal with them on the supplying of gas for our utilities there in those two facilities.

Would that come under this?

Would you have something to say about conservation there? Is that what you are worrying about, Don, are those private gas producers and suppliers falling under this regulation?

Senator NICKLES. I am worried about two primary things. One, I can see a massive—well, one you have got electric utilities, which I think have—I will separate that—the gas utilities moving into a reregulated market, where we are interfering with the state commissions who, in many cases, have been working very—and correct me if I am wrong, have not most of the state commissions been working, trying to develop some type of least cost approaches? Maybe doing it voluntarily, maybe doing it with encouragements, but they have been doing it.

I am concerned about us preempting or mandating that, whether it be electric or the gas. I am concerned about some way or another driving gas prices down, or regulating gas prices. Again, I do not know how you define the, you know, to include all of the environmental costs and other costs. I do not know that we want to. It is so vague and big and indefinable, and—let me finish.

But then, also, my very, very strong concern that I have and very strong opposition that I have would be the Section 313, the purchases of qualifying conservation by the utilities.

I heard the statements made by our witnesses, but this PURPA has had, maybe some good effects. It has contributed some energy sources and supplies.

But I can also tell you we have significant utilities that are buying a lot of power at absurd prices, prices well outside of what I am going to say is the marketplace, and consumers are paying for that and they are going to be paying for it for years, and I question the wisdom of that.

So I certainly question the wisdom of expanding it and I really question the wisdom of having those same utilities have to go out and write checks for perceived conservation, and I say perceived, because how do you quantify it?

Well, was that factory going to reduce its consumption of energy, anyway? Were they going to close part of it? Were they going to make significant model changes, energy conservation changes anyway, just to be competitive?

I happen to think that the marketplace is the better source of initiative to make those kind of changes. I really question whether we want these utilities, and of course if the utilities are going to be writing the checks, the customers of the utilities are going to be writing those checks for this perceived conservation.

It may happen, and do not get me wrong, I am not an opponent of conservation. I want to encourage conservation. What I do not want to encourage is setting up a massive bureaucracy, maybe with flexibility by FERC or DOE to set these standards, but I mean I can see all kinds of abuses.

I am from the private sector and energy costs are a significant concern for any concern, probably, whether it is the homeowner or whether it is the plant. I would hate to think that someone could receive a benefit if they close their plant down so they can say, hey, we had energy conservation, and you know, maybe they are going to close the plant down anyway, I do not know.

I just think we have to be very, very careful and I have not seen the justification for proceeding with something that could be so expensive for consumers as Section 313. When I made my opening statement, I said I thought it was a bad idea. I continue to think that, but I look forward again to learning more about it, but the more I learn about it the more I think that we need to delete this section from any bill.

Senator McCLURE. Would the Senator yield?

Senator NICKLES. I would be happy to.

Senator McCLURE. The Senator touched on one thing a moment ago which I think demands some response, or at least some expansion on the record, and that is with respect to what might be termed the difference between short-term and long-term movements in the market, or reactions by utilities or regulatory agencies.

There is an on-going debate in this country about whether or not we should continue the demand upon the utilities to provide reliable and available service to the consumers, and where does reliability stand on the scale of responsibilities of a utility serving customers?

There is on page 29 of the bill a passing reference to the fact that they must provide adequate and reliable service to consumers. That is the only reference I am aware of at the moment in this bill to that on-going debate, and it may well be that we need to expand on that in the legislation if, indeed, that is our desire, to make certain that we do not penalize consumers in the long run in order to get short-term perceived benefits.

Now, certainly the regulatory bodies, whether it be FERC at the Federal level or the state regulatory agencies take that into account, and if you deal with the unregulated utilities, and this is to apply to them a separate question I assume that may well apply to them.

Somebody has to make that decision with respect to them as to what may be done under this legislation with respect to that other obligation on the other side, with respect to reliability of service and the availability of supply.

Senator WIRTH. We have a vote coming up.

Again, let me ask you to—I think Senator Nickles has raised again part of the Federal question in the second question that he raised. How much section 313—how far do we go from a Federal level, first to knock down regulatory barriers or to encourage utilities, secondly how aggressively do we get into creating that kind of a third party right?

That is the part of the Federal model versus the second track that you all are going to pursue and come back to us on, the model that is suggested in your legislation.

The issue of natural gas was, as you all know, part of the debate as we put together the first draft of this. Any thoughts that you all had on that would be welcome as well, and Senator McClure raises the—you know, how do we focus more on the consumer issues? What else might there be? Any comments that you would have there would be welcome.

The Committee is going to adjourn. We are coming back on November 7th with non-Federal witnesses on these same issues and look forward to hearing them. The record will be left open for questions from the Committee.

I noted Senator Metzenbaum has questions and I think Senator McClure has questions, and others do.

I think we have framed broadly what the main issues are here, and we really appreciate you being here. It has been a very helpful hearing and you got off easily, Miss Stuntz, on the other issues. We were going to talk about, as well, global warming strategy—and I see the gratitude on your face. [Laughter.]

The Committee stands adjourned.

[Whereupon, at 10:45 a.m., the hearing was adjourned, subject to the call of the Chair.]

NATIONAL ENERGY POLICY ACT OF 1989 (PURPA)

TUESDAY, NOVEMBER 7, 1989

U.S. SENATE,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The Committee met, pursuant to notice, at 9:30 a.m., in room SD-366, Dirksen Senate Office Building, Hon. Timothy E. Wirth presiding.

OPENING STATEMENT OF HON. TIMOTHY E. WIRTH, U.S. SENATOR FROM COLORADO

Senator WIRTH. Good morning. The committee will come to order.

Today we are continuing hearings on the National Energy Policy Act of 1989, legislation designed to address the problem of global warming. This committee is set, of course, to take a leadership position on this issue. Looking at today's newspaper, it is clear that this administration is firm in its decision to abdicate a leadership role for the United States.

Many of us objected to the decision made two weeks ago to stifle the EPA Administrator's plans to go to the ministerial summit in the Netherlands with an aggressive plan to assert U.S. leadership on the issue.

The nay-sayers at the White House prevailed over the scientific and environmental experts, who warned that we urgently need to begin reducing emissions of carbon dioxide and greenhouse gases.

The decision to scuttle Mr. Reilly's plans were bad enough. Today the situation appears to be worse than we thought. We are learning that the United States is one of less than a handful of nations opposed to common efforts to reduce greenhouse emissions.

It is a sad state of affairs when the United States is in the position of rejecting the warnings of our best scientific experts. Worse still, we are trying to block a consensus for an international position.

Clearly, our policy is outside the national and international mainstream. Every respectable scientist in the world believes the growing emissions of carbon dioxide will alter the climate. Further, our scientists are telling us that they believe that the results of climate change will be catastrophic for this and all nations.

We are assaulting the fundamental forces of nature, and the administration's position is so irresponsible that it borders on recklessness. We have to turn this around, and that is why we are here today.

Two weeks ago we received testimony from the Federal Energy Regulatory Commission and the Department of Energy. At that hearing, DOE and FERC raised a number of concerns about the implementation of the provisions of subtitle B, Title III of this legislation.

I asked our witnesses to get back to the committee with specific recommendations on how this language could be improved to address these concerns, and we look forward to their input.

Today we are receiving testimony from individuals who work outside the confines of the Washington bureaucracy, witnesses from the field, so to speak. Based on their written testimony, I believe that the majority of our witnesses address a number of the concerns that were expressed by DOE and FERC two weeks ago.

It is clear to me that conservation can be quantified, it can be measured, and it can be reliable. In several states, energy efficiency is emerging as a cornerstone of energy planning. Our national interest lies clearly in the direction of energy efficiency, and I believe the Federal Government has a responsibility to encourage the development of efficiency across the country.

Unfortunately, virtually every analyst agrees that we are not acquiring all the cost-effective energy efficiency improvements that are available in the marketplace. Subtitle B of Title III is designed to provide a flexible, state-controlled initiative to tap the potential of energy efficiency.

The basic thrust of these provisions is to encourage equal treatment of supply and demand resources. If we can craft these provisions properly, we can realize the environmental, economic and competitive benefits of energy efficiency.

I look forward to working with our witnesses and others in developing this proposal. We will begin our first panel with Cheryl Harrington, representing the National Association of Regulatory Utility Commissions; Thomas Morron of the Edison Electric Institute; Larry Hobart of the American Public Power Association; and Charles Cicchetti of the JFK School of Government at Harvard.

But before proceeding to our witnesses, let me ask the distinguished Senator from Kentucky if he has any opening remarks he might like to make.

Senator FORD. No, I do not have anything, Mr. Chairman. I am going to keep my focus on the National Energy Policy this morning if I possibly can, and not stray too far away from what we are trying to do.

Thank you, sir.

Senator WIRTH. Thank you.

[The prepared statements of Senators Wirth and Johnston follow:]

STATEMENT OF THE HONORABLE TIMOTHY E. WIRTH

Good morning. Today we will be continuing hearings on the "National Energy Policy Act of 1989," a bill designed to address the problem of global warming.

This committee has set a course to take a leadership position on this issue. Looking at today's newspaper, it is clear that the Administration is firm in its decision to abdicate a leadership role for the United States. Many of us objected to the decision made two weeks ago to stifle the EPA Administrator's plans to go the ministerial summit in the Netherlands with an aggressive plan to assert U.S. leadership on the issue. The naysayers at the White House prevailed over the scientific and environmental experts who warn that we urgently need to begin reducing emissions of carbon dioxide and greenhouse gases.

The decision to scuttle Mr. Reilly's plans was bad enough. Today, the situation appears to be worse than we thought. We are learning that the United States is one of less than a handful of nations opposed to common efforts to reduce greenhouse gas emissions. It is a sad state of affairs when the United States is in the position of rejecting the warnings of our best scientific experts. Worse still, we are trying to block a consensus international position.

Clearly, our policy is outside the national and international mainstream. Every respectable scientist in the world believes that growing emissions of carbon dioxide will alter the climate. Further, our scientists are telling us that they believe that the results of climate change will be catastrophic for this and all nations. We are assaulting the fundamental forces of nature and the Administration's position is so irresponsible that it borders on reckless. We have to turn this around and that is why we are here today.

Two weeks ago, we received testimony from the Federal Energy Regulatory Commission and the Department of Energy. At that hearing, DOE and FERC raised a number of concerns about the implementation of the provisions of Subpart B, Title III of this legislation. I asked our witnesses to get back to the committee with specific recommendations of how this language could be improved to address these concerns and we look forward to their input.

Today, we are going to receive testimony from individuals who work outside the confines of the Washington bureaucracy, witnesses from the "field" so to speak. Based on their written testimony, I believe the majority of our witnesses address a number of the concerns expressed by DOE and FERC two weeks ago. It is clear to me that conservation can be quantified, it can be measured and it can be reliable.

In several states, energy efficiency is emerging as a cornerstone of the energy planning process. Our national interest, however, lies clearly in the direction of energy efficiency, and I believe the federal government has a responsibility to encourage the development of energy efficiency across the country.

Unfortunately, virtually every analyst agrees that we are not acquiring all of the cost-effective energy efficiency improvements that are available in the marketplace. Subpart B, Title III of S. 324 is designed to provide a flexible, state-controlled initiative to tap the potential of energy efficiency. The basic thrust of these provisions is to encourage equal treatment of supply and demand side resources. If we can craft these provisions properly, we can realize the environmental, economic and competitive benefits of energy efficiency.

I look forward to working with our witnesses and others in further developing this proposal. We will begin our first panel with Cheryl Harrington, representing the National Association of Regulatory Utility Commissions; Thomas Morron of the Edison Electric Institute; Larry Hobart of the American Public Power Association; and Charles Chichetti of the JFK School of Government at Harvard.

OPENING STATEMENT OF SENATOR J. BENNETT JOHNSTON
SECOND HEARING ON PURPA PROVISIONS OF S. 324, THE "NATIONAL ENERGY POLICY ACT OF 1989"

We are here this morning for the second of our hearings on legislation that would amend the Public Utility Regulatory Policies Act of 1978, known by its acronym as PURPA. The bill before us, S. 324, the "National Energy Policy Act of 1989" includes two amendments to PURPA.

The first of these amendments appears to be non-controversial and addresses a general problem in utility ratemaking. Typically, electric and gas rates are structured so that utility earnings increase with the more gas or electricity a utility sells. There is, therefore, a disincentive for a utility to engage in least cost planning to the extent that the least cost resource in any given instance is a conservation measure which reduces utility sales. The first proposed amendment would simply require state utility commissions and unregulated utilities to consider changing ratemaking practices so as to remove the existing disincentive for least cost planning.

The second PURPA amendment is more problematic. It would create "qualifying conservation" which is to be treated analogously to qualifying facilities under the existing provisions of PURPA. Specifically, utilities would be required to buy qualifying conservation from "qualifying conservation entities" at rates ultimately determined by state commissions. Qualifying conservation is defined by the bill as a reduction in electric demand at any time that would not occur but for payments by a utility.

The initiation of a mandatory purchase program for conservation creates a host of serious concerns. For example, in the context of a mandatory program can the reliability of purchased conservation be guaranteed? As a practical matter can we separate conservation produced by utility payments from conservation that would occur anyway? Perhaps most importantly, can we devise a pricing regime which ensures that utilities are not required to buy conservation whose true cost exceeds the cost of supply side alternatives?

These questions and others are significant. They must be satisfactorily answered before we move forward with qualifying conservation. At our last hearing on this subject we received confirmation from the Department of Energy and the Federal Energy Regulatory Commission that there are indeed many practical problems associated with the implementation of qualifying conservation. Yet as Senator Wirth has pointed out, we owe it to ourselves to take a good hard look before we dismiss creative possibilities such as this one.

Our hearing this morning will continue the Committee's hard look at the two PURPA amendments. We will get the perspective of conservation advocates, investor-owned utilities, state regulators, public power and prominent economists. Perhaps their views will differ from those we have heard; perhaps they will not. I look forward to hearing from our witnesses.

Senator WIRTH. Tom, do you want to start us off? Ms. Harrington is not here yet.

STATEMENT OF THOMAS D. MORRON, VICE PRESIDENT, CUSTOMER SERVICES AND MARKETING, EDISON ELECTRIC INSTITUTE

Mr. MORRON. Thank you, Senator.

The electric utility industry believes that rational public policy can in fact be crafted to address the issue of global climate change, and we are already taking as quite serious the possible consequences of continued increases in so-called greenhouse gases.

For example, today there are some 1,300 utility-sponsored demand-side management programs, and the industry spends in excess of $1 billion per year in support of these efforts, and that amount continues to increase.

The demand reductions resulting from these efforts since the year 1977 are estimated by the Electric Power Research Institute at more than 21,000 megawatts to date, and are projected to exceed some 45,000 megawatts by the year 2000.

Our industry's commitment also means development of new and more efficient end-use applications, such as through research conducted by the Electric Power Research Institute and supported by industry-wide funding.

Further progress along these lines requires continued support from state commissions to permit utilities the flexibility to conduct programs tailored to meet local needs. Electric utilities continue to work closely with state regulatory commissions and customers to find ways in which demand-side management programs might be improved.

Increasingly, growing public concern over possible global climate change has prompted calls for limitations on or no growth in the use of electricity. In fact, efficiency can be improved and environmental impacts reduced by selective application of modern electric technologies and substitution for older fossil fuel technologies.

Appendix B to my testimony is a copy of a study conducted this past summer, which looks at the potential for reducing emissions of carbon dioxide through substitution of electric technologies for those currently employing fossil fuel at the point of end use.

It highlights the potential for a reduction of about 17 percent of the U.S. industrial sector's total annual carbon dioxide emission and a reduction of about 8 percent of the transportation sector total annual carbon dioxide emissions, despite increasing electricity consumption.

Overall, we believe it to be poor public policy to set arbitrary limits on the use of electricity resources in the mistaken assumption that an increase in electricity demand will automatically mean an increase in atmospheric pollutants.

Improvements in energy efficiency must not be limited by definition to only those actions which reduce electric energy consumption.

Turning to the legislation before the committee. With respect to least-cost planning, I would note that from the industry's perspective, the purpose of least-cost planning is to optimize supply and demand decisions made by the electric utility so as to provide an adequate, reliable supply to its customers at the lowest cost, commensurate with environmental quality.

I would call to your attention that some 43 of the 50 state regulatory commissions are already engaged in the process of determining the most appropriate least-cost plans for their unique circumstances.

The National Association of Regulatory Utility Commissions, NARUC, and industry associations have supported the development of least-cost planning through seminars and research activities, new concepts, such as providing financial incentives for utility demand-side programs, and improved understanding of proper pricing approaches for demand-side measures.

In the absence of any finding that these efforts are inadequate in some fashion, we would question the need for federal legislation which would require the entire costly and time-consuming process to be repeated.

We agree that cost-effective demand-side management programs should be encouraged and their effects incorporated into the planning process. However, we oppose federally-mandated treatment of such efforts as a supply resource.

The industry is extremely concerned over the concept of qualifying conservation entities for the same reasons as the federal witnesses, who appeared before this committee on October 26th of this year.

One concern is that the definition can include reductions achieved simply by switching from electricity to other fuel sources. Such switching is not necessarily energy efficient, nor will it necessarily lead to a reduction of emissions.

Other issues include how to define cost-effectiveness, how to address actual versus forecasted savings, controlling for changed occupancy behavior, weather and rate changes over time, how to verify program participation, dealing with changes to programs as they evolve, and how to quantify the environmental benefits and costs of demand-side programs.

Federal Energy Regulatory Commission staff and DOE witnesses, in recent testimony, emphasize the difficulties of verification and other reasons why qualifying conservation would produce complexities far beyond those under the existing qualifying facilities program under PURPA.

The Alliance to Save Energy recently completed a study which illustrates the uncertainty associated with demand-side efficiency improvements. Engineering evaluations in this study had shown that installing new burners in some 60 homes improved the heating systems efficiency by some 20 percent. But in only five years time, the study observed an actual average improvement of only 13.2 percent.

It is for just such reasons utility planners prefer to treat energy efficiency improvements as a reduction in the forecasted demand, rather than as actual generating capacity instantly available for customers. This distinction, we believe, is critically important.

From a utility planning perspective, if your customers do not require as much power as you thought they might, you may in fact have built too much capacity. On the other hand, if your customers require more than you forecast, you may not have built enough.

And the result of that is economic and social disruption on a staggering scale.

You have no choice, in short, but to be sure that sufficient capacity will be there when your customers need it. The economic evaluation of demand-side programs must be integrated with supply-side planning to ensure reliable, flexible and economically-efficient resource strategies for the specific characteristics of each utility.

The existing mix of generating units, fuel contracts, environmental control strategies, load shape, and future economic activity should all play a role in determining the size, type, timing and balance between supply- and demand-side resources.

Obviously, a federal mandate cannot appropriately meet the needs of each individual utility. Therefore, we believe the best policy position is to allow utilities, working with their state commissions, to determine how demand-side options should be included in the planning process, rather than imposing a federal standard.

This would conclude my highlight of my written testimony.

Thank you, Mr. Chairman.

[The prepared statement of Mr. Morron follows:]

TESTIMONY OF THOMAS D. MORRON

Vice President, Customer Services and Marketing

Edison Electric Institute

Before The

UNITED STATES SENATE

ENERGY AND NATURAL RESOURCES COMMITTEE

on the

National Energy Policy Act of 1989

Subtitle B of Title III of S. 324

November 7, 1989

TESTIMONY OF THOMAS D. MORRON
Vice President, Customer Services and Marketing
Edison Electric Institute
Before The
UNITED STATES SENATE
ENERGY AND NATURAL RESOURCES COMMITTEE
NOVEMBER 7, 1989

GOOD MORNING LADIES AND GENTLEMEN. MY NAME IS THOMAS D. MORRON AND I AM VICE PRESIDENT, CUSTOMER SERVICES AND MARKETING, AT THE EDISON ELECTRIC INSTITUTE. THE EDISON ELECTRIC INSTITUTE IS THE ASSOCIATION OF INVESTOR-OWNED ELECTRIC COMPANIES. ITS MEMBERS SERVE 96 PERCENT OF ALL CUSTOMERS SERVED BY THIS SEGMENT OF THE INDUSTRY. THEY GENERATE APPROXIMATELY 78 PERCENT OF ALL THE ELECTRICITY USED IN THE COUNTRY AND SERVICE 74 PERCENT OF ALL ULTIMATE CUSTOMERS IN THE NATION.

WE ARE GRATEFUL FOR THE OPPORTUNITY TO COMMUNICATE OUR VIEWS AS AN INDUSTRY TO THIS COMMITTEE REGARDING THE ISSUE OF LEAST-COST INVESTMENT. WE BELIEVE THAT ISSUES OF ENERGY SUPPLY AND DEMAND ARE CRITICAL TO THE FUTURE OF OUR NATION, AND THAT THESE ISSUES SHOULD BE ADDRESSED IN THE CONTEXT OF MAINTAINING THE QUALITY OF OUR GLOBAL ENVIRONMENT. AS THE MEMBERS OF THIS COMMITTEE ARE WELL AWARE, THESE ISSUES ARE EXTRAORDINARILY COMPLEX AND DO NOT LEND THEMSELVES TO SIMPLE SOLUTIONS. THEY REQUIRE CAREFUL CONSIDERATION AND DELIBERATION, AS THE CONSEQUENCES OF ERROR CAN BE EXTREMELY

SERIOUS FOR OUR NATION AND OUR GLOBAL NEIGHBORS.

MR. WILLIAM MCCOLLAM, JR., PRESIDENT OF THE EDISON ELECTRIC INSTITUTE, PRESENTED TESTIMONY TO THIS COMMITTEE DURING HEARINGS HELD ON S. 324 ON MARCH 14 OF THIS YEAR. A COPY IS ATTACHED AS APPENDIX A. HIS TESTIMONY IS DIRECTLY RELEVANT TO THESE PROCEEDINGS, AND WE URGE THE COMMITTEE TO INCORPORATE THOSE COMMENTS IN THE RECORD OF ITS DELIBERATIONS HERE TODAY.

THERE IS CONSIDERABLE SCIENTIFIC UNCERTAINTY ABOUT WHEN AND HOW AN "ENHANCED GREENHOUSE EFFECT" MAY EFFECT THE INTERRELATED AREAS OF AGRICULTURE, RAINFALL, HYDROLOGY, SEA LEVEL, STORM EVENTS, AND DEMOGRAPHY. THE DEBATE HAS BEEN HIGHLY CHARGED AND AT TIMES CONTENTIOUS. HOWEVER, THE ELECTRIC UTILITY INDUSTRY BELIEVES THAT RATIONAL PUBLIC POLICY CAN BE CREATED TO ADDRESS THIS ISSUE. MOREOVER, WE ARE ALREADY TAKING AS SERIOUS THE POSSIBLE CONSEQUENCES OF CONTINUED INCREASES IN WHAT HAVE BEEN CALLED "GREENHOUSE GASES."

THE INDUSTRY BELIEVES THAT RATIONAL PUBLIC POLICY SHOULD ADOPT A HOLISTIC APPROACH TO THIS ISSUE, RATHER THAN FOCUS ON PARTICULAR SUB-ISSUES. FURTHER, THIS INDUSTRY IS ALREADY PURSUING SEVERAL PATHS DESIGNED TO MEET THE NATION'S ENERGY NEEDS WHILE REDUCING ATMOSPHERIC EMISSIONS, SUCH AS BY THE DEVELOPMENT OF DIVERSE ENERGY SOURCES.

OVERVIEW

IT IS IMPORTANT TO EMPHASIZE--IN THE STRONGEST POSSIBLE TERMS--THAT THE ELECTRIC UTILITY INDUSTRY AND ITS CUSTOMERS HAVE ALREADY COMBINED TO ACHIEVE SUBSTANTIAL IMPROVEMENTS IN EFFICIENT

PRODUCTION AND USE OF ELECTRICITY. FURTHER, ENERGY EFFICIENCY PLAYS A CRUCIAL ROLE IN CURRENT INDUSTRY PLANNING TO PROVIDE AN ADEQUATE, RELIABLE, AFFORDABLE AND ENVIRONMENTALLY SOUND ELECTRICITY SUPPLY FOR THE FUTURE.

NEVERTHELESS, THE PROPOSED AMENDMENTS TO THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 (PURPA) AND THE FEDERAL POWER ACT AS CONTAINED IN SUBTITLE B OF TITLE III OF S. 324, THE "NATIONAL ENERGY POLICY ACT OF 1989," RAISE SEVERAL SERIOUS CONCERNS WHICH ARE SUMMARIZED AS FOLLOWS:

- EFFICIENT END-USE ENERGY APPLICATIONS, SUCH AS THOSE WHICH SUBSTITUTE ELECTRICITY FOR FOSSIL FUELS AND REDUCE NET EMISSIONS, MAY NOT APPEAR TO BE LEAST-COST SUPPLY MEASURES AS DEFINED BY THE BILL SINCE THEY INCREASE THE USE OF ELECTRICITY.
- UTILITIES AND STATE REGULATORS IN 43 STATES ARE ALREADY ENGAGED IN THE PROCESS OF DETERMINING THE MOST APPROPRIATE "LEAST-COST PLANS" FOR THEIR UNIQUE CIRCUMSTANCES. WE QUESTION THE NEED FOR FEDERAL LEGISLATION WHICH WOULD REQUIRE THAT ENTIRE COSTLY AND TIME-CONSUMING PROCESS TO BE REPEATED.
- IT IS NOT ECONOMICALLY AND TECHNICALLY APPROPRIATE TO TREAT SAVED KILOWATTS AS IF THEY WERE THE SAME AS GENERATED KILOWATTS.

THE FOLLOWING DISCUSSION WILL DESCRIBE IN DETAIL WHY THE INDUSTRY FEELS THAT THE PURPA PROVISIONS OF S. 324 ARE NEITHER NECESSARY NOR APPROPRIATE.

INDUSTRY COMMITMENT TO ENERGY EFFICIENCY

THE HISTORY OF THIS INDUSTRY CLEARLY DEMONSTRATES OUR LONG-TERM COMMITMENT TO ENERGY EFFICIENCY. TODAY, THERE ARE NEARLY 1,300 UTILITY-SPONSORED DEMAND-SIDE MANAGEMENT PROGRAMS DESIGNED TO INCREASE CUSTOMER END-USE EFFICIENCY, AN INCREASE FROM ABOUT 134 IN 1977. THESE EFFORTS COVER ALL MARKET SECTORS IN A WIDE VARIETY OF WAYS. THEY RANGE FROM THE PROVISION OF INFORMATIONAL MATERIALS FOR CUSTOMER USE TO DIRECT CONTROL OF CUSTOMER LOADS. THEY RUN THE GAMUT FROM MASS MEDIA ADVERTISING TO ON-SITE ENERGY AUDITS. THEY INCLUDE INCENTIVES RANGING FROM INNOVATIVE PRICING STRUCTURES TO DIRECT CASH REBATE PAYMENTS FOR THE PURCHASE OF HIGH EFFICIENCY, END-USE EQUIPMENT. THEY ALSO INCLUDE ZERO OR BELOW-MARKET INTEREST RATE FINANCING OF EFFICIENCY IMPROVEMENTS, SHARED SAVINGS PROGRAMS, DIRECT MARKETING OF NEW EFFICIENCY TECHNOLOGIES, CONSTRUCTION DESIGN ASSISTANCE AND GUIDELINES, IRRIGATION PUMP TESTING, RE-LAMPING PROGRAMS AND MANY OTHERS. THIS LISTING IS INCOMPLETE, BUT IS, NEVERTHELESS, ILLUSTRATIVE OF THE BROAD RANGE OF ACTIVITIES BY WHICH WE AGGRESSIVELY SEEK TO IMPROVE ENERGY EFFICIENCY. THE ELECTRIC UTILITY INDUSTRY NOW SPENDS IN EXCESS OF $1 BILLION PER YEAR IN SUPPORT OF THESE EFFORTS, AND THE AMOUNT CONTINUES TO INCREASE.

THE RESULTS OF THESE EFFORTS ARE NO LESS IMPRESSIVE. THE DEMAND REDUCTIONS WHICH ARE A DIRECT RESULT OF THESE EFFORTS SINCE 1977 ARE ESTIMATED BY THE ELECTRIC POWER RESEARCH INSTITUTE AT MORE THAN 21,000 MEGAWATTS TO DATE, AND ARE PROJECTED TO EXCEED 45,000 MEGAWATTS BY THE YEAR 2000. IF ONE WERE TO ASSUME A VERY

CONSERVATIVE CONSTRUCTION COST FOR NEW CAPACITY OF $1,000 PER KILOWATT, THIS MEANS THAT SOMETHING ON THE ORDER OF $21 BILLION OF NEW CAPACITY INVESTMENT HAS BEEN AVOIDED SO FAR, AND AS MUCH AS $45 BILLION WOULD BE SAVED BY THE YEAR 2000.

EFFICIENCY IMPROVEMENTS IN ENERGY PRODUCTION PLAY A CRUCIAL ROLE IN ELECTRIC UTILITY SUPPLY-SIDE PLANNING STRATEGIES FOR PROVIDING ADEQUATE, RELIABLE, AFFORDABLE, AND ENVIRONMENTALLY SOUND ENERGY SERVICES. SIMPLE ECONOMICS AND MARKET FORCES, WITHOUT GOVERNMENT INTERVENTION, HAVE DRIVEN THE INDUSTRY TO IMPROVE THE EFFICIENCY OF ELECTRIC GENERATION. ACCORDING TO OUR CALCULATIONS USING DATA FROM THE NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL (NERC), IMPROVEMENTS IN THE EQUIVALENT AVAILABILITY FACTOR (A MEASUREMENT OF PLANT AVAILABILITY) CAN BE EQUATED TO NEW CAPACITY EXPENDITURES OF ALMOST $77 BILLION DOLLARS FROM 1984 THROUGH 1988. ACTUAL SAVINGS, WHICH HAVE BEEN REALIZED OR WILL BE REALIZED, DEPEND ON CAPACITY REQUIREMENTS ON A SYSTEM BY SYSTEM BASIS. THE ALMOST THREE PERCENT IMPROVEMENT IN AVAILABILITY OVER THAT FOUR YEAR PERIOD HAS ENABLED THE INDUSTRY TO RELY MORE HEAVILY ON CLEANER, MORE EFFICIENT GENERATING UNITS, THUS REDUCING ENVIRONMENTAL IMPACTS WHILE ALSO REDUCING COSTS.

OUR INDUSTRY'S COMMITMENT TO ENERGY EFFICIENCY ALSO MEANS DEVELOPMENT OF NEW AND MORE EFFICIENT END-USE APPLICATIONS, AS EVIDENCED BY RESEARCH CURRENTLY BEING CONDUCTED AT THE ELECTRIC POWER RESEARCH INSTITUTE AND BACKED BY INDUSTRY-WIDE FUNDING. IN ADDITION, OUR INDUSTRY CONTINUES TO SUPPORT SENSIBLE LEGISLATION TO PRODUCE GREATER GAINS IN EFFICIENCY, SUCH AS THE NATIONAL

APPLIANCE ENERGY CONSERVATION ACT OF 1987 AND THE NATIONAL APPLIANCE ENERGY CONSERVATION AMENDMENTS OF 1988.

FURTHER PROGRESS ALONG THESE LINES REQUIRES CONTINUED SUPPORT FROM STATE COMMISSIONS TO PERMIT UTILITIES THE FLEXIBILITY TO CONDUCT PROGRAMS TAILORED TO LOCAL NEEDS, WHICH HOLD THE PROMISE OF AN INCREASED RANGE OF SERVICES AVAILABLE TO CUSTOMERS IN ALL MARKET SEGMENTS. FURTHER PROGRESS ALSO REQUIRES ADOPTION OF SUCH MODEL ENERGY CODES AS THE ONE RECENTLY PROMULGATED BY THE COUNCIL OF AMERICAN BUILDING OFFICIALS, COVERING ENERGY EFFICIENCY IN NEW CONSTRUCTION. THIS CODE RECENTLY RECEIVED FURTHER ENDORSEMENT BY THE ALLIANCE TO SAVE ENERGY IN TESTIMONY BEFORE THE HOUSE SUBCOMMITTEE ON ECONOMIC STABILIZATION.

BY VIRTUALLY ANY STANDARD OF JUDGMENT, THIS RECORD OF ACCOMPLISHMENT IS INDICATIVE OF A SERIOUS AND LONG-TERM COMMITMENT TO ENERGY EFFICIENCY. FURTHER, ELECTRIC UTILITIES CONTINUE TO WORK CLOSELY WITH OUR STATE REGULATORY COMMISSIONS AND OUR CUSTOMERS TO FIND WAYS IN WHICH DEMAND-SIDE MANAGEMENT (DSM) PROGRAMS CAN BE IMPROVED. AS I HAVE MENTIONED, SOME 43 STATE REGULATORY COMMISSIONS ARE CURRENTLY WORKING WITH THEIR LOCAL UTILITIES AND WITH INTERESTED CUSTOMER GROUPS IN APPLYING DEMAND-SIDE PRINCIPLES TO THE DEVELOPMENT OF WHAT HAS BECOME KNOWN AS "LEAST-COST PLANS."

FROM THE INDUSTRY'S PERSPECTIVE, THE PURPOSE OF LEAST-COST PLANNING IS TO OPTIMIZE SUPPLY AND DEMAND DECISIONS MADE BY THE ELECTRIC UTILITY, SO IT CAN PROVIDE AN ADEQUATE, RELIABLE SUPPLY OF ELECTRICITY TO ITS CUSTOMERS AT THE LOWEST COST CONSISTENT WITH ENVIRONMENTAL QUALITY. IN THIS FRAMEWORK, SPECIFIC DEMAND-SIDE

OPTIONS ARE CONSIDERED, AND INTEGRATED WITH SUPPLY-SIDE OPTIONS. PARTICULAR INVESTMENT OPTIONS AND OPERATING STRATEGIES ARE THEN SELECTED, CONSISTENT WITH THE UTILITY'S MANY OVERALL OBJECTIVES.

A PRIMARY OBJECTIVE IN ELECTRIC UTILITY PLANNING IS TO KEEP COSTS AS LOW AS POSSIBLE. THIS OBJECTIVE CAN SOMETIMES BE PURSUED BY POSTPONING CONSTRUCTION OF NEW BASE LOAD PLANTS THROUGH THE IMPLEMENTATION OF DEMAND-SIDE MANAGEMENT PROGRAMS. HOWEVER, SUCH PROGRAMS ARE ONLY ONE WAY TO LOWER COSTS, AND ACHIEVING THE LOWEST COST IS NOT THE ONLY UTILITY OBJECTIVE. OTHER PRIMARY OBJECTIVES ARE ENVIRONMENTAL QUALITY AND SYSTEN RELIABILITY.

ELECTRIC VALUE AND ENVIRONMENTAL QUALITY

INCREASINGLY, THE GROWING PUBLIC CONCERN OVER POSSIBLE GLOBAL CLIMATE CHANGE HAS PROMPTED CALLS FOR ABSOLUTE LIMITATIONS ON, OR NO GROWTH IN, THE USE OF ELECTRICITY IN THE UNITED STATES. WE BELIEVE THAT SUCH A POLICY WOULD DEPRIVE THIS NATION OF AN EXTREMELY VALUABLE TOOL IN IMPROVING NOT ONLY ENVIRONMENTAL QUALITY, BUT THE COMPETITIVE POSITION OF THE NATION'S INDUSTRIES IN WORLD MARKETS.

APPENDIX B TO MY TESTIMONY IS A COPY OF A STUDY CONDUCTED THIS PAST SUMMER WHICH LOOKS AT THE POTENTIAL FOR REDUCING EMISSIONS OF CARBON DIOXIDE (CO2) THROUGH SUBSTITUTION OF ELECTROTECHNOLOGIES FOR TECHNOLOGIES CURRENTLY EMPLOYING FOSSIL FUELS AT THE POINT OF END-USE IN THE INDUSTRIAL AND TRANSPORTATION SECTORS. WE DO NOT CHARACTERIZE THIS PRELIMINARY RESEARCH EFFORT AS DEFINITIVE. HOWEVER, IT DOES HIGHLIGHT THE POTENTIAL FOR THE REDUCTION OF ABOUT

17 PERCENT OF THE U.S. INDUSTRIAL SECTOR'S TOTAL ANNUAL CO2 EMISSIONS, AND A REDUCTION OF ABOUT 8 PERCENT OF THE TRANSPORTATION SECTOR'S TOTAL ANNUAL CO2 EMISSIONS.

WHILE SUCH SUBSTITUTIONS INCREASE THE DEMAND FOR ELECTRICITY, THE NET EFFECT ON THE ENVIRONMENT WILL STILL BE A DECREASE IN CO2 EMISSIONS. THE FINDINGS OF THIS RESEARCH CAN STIMULATE THE CONTINUED DEVELOPMENT AND PROMOTION OF HIGHLY EFFICIENT ELECTROTECHNOLOGIES. NOT ONLY WILL THESE ELECTROTECHNOLOGIES DECREASE THE PRODUCTION OF CO2 AS WELL AS OTHER POLLUTANTS, BUT THEY CAN ALSO INCREASE INDUSTRIAL COMPETITIVENESS. THE REPORT MENTIONS A NUMBER OF SPECIFIC ELECTROTECHNOLOGIES, BUT LET ME JUST MENTION TWO TO ILLUSTRATE MY POINT.

SHORT-WAVE ELECTRIC INFRARED PAINT CURING IS AN EXCELLENT EXAMPLE OF THE POTENTIALS OF ELECTROTECHNOLOGY. A MANUFACTURING FIRM IN GEORGIA MAKES ALUMINUM COLUMNS FOR THE FRONT OF NEOCLASSICAL BUILDINGS. FOR YEARS, ITS PROCESS INVOLVED PAINTING THE COLUMNS AND BAKING THEM IN NATURAL GAS CONVECTION OVENS. BETWEEN PAINT LOSSES AND ENVIRONMENTAL PROBLEMS WITH THE RELEASED SOLVENTS, THE COMPANY HAD TO FIND A BETTER METHOD.

IT REPLACED ITS OLD PROCESS WITH ELECTROSTATICALLY-APPLIED POWDERED PAINT, WHICH IS THEN CURED BY SHORT-WAVE INFRARED RADIATION. THE MAJOR RESULTS INCLUDE GREATLY REDUCED EMISSIONS OF POLLUTANTS, REDUCED MATERIAL LOSS AND IMPROVED PRODUCT QUALITY AND PRODUCTION SPEED GAINS AS WELL AS ENERGY SAVINGS. THE ELECTRIC PROCESS TAKES 34 SECONDS INSTEAD OF 60 MINUTES.

TECHNOLOGY SIMILAR IN PRINCIPLE TO THIS HAS BEEN RECENTLY

INSTALLED IN AN ILLINOIS CHRYSLER CORPORATION AUTO PAINTING PLANT. THE COMPANY IS FINDING THAT, IN ADDITION TO THE ENVIRONMENTAL AND EFFICIENCY BENEFITS MENTIONED IN CONNECTION WITH THE GEORGIA COMPANY, THIS TECHNOLOGY YIELDS A SHINIER AND MORE LUSTROUS FINISH.

A SECOND EXAMPLE IS GLASS PRODUCTION. MELTING IS THE MOST ENERGY-INTENSIVE STAGE OF GLASS PRODUCTION. IT ACCOUNTS FOR 43 TO 85 PERCENT OF TOTAL ENERGY NEEDS. DURING THIS PROCESS, DRY PRODUCTS ARE CONTINUALLY ADDED TO A POOL OF MOLTEN GLASS. TEMPERATURES OF 2,500 DEGREES FAHRENHEIT ARE TYPICALLY REQUIRED. THE MOST COMMON FURNACE USED FOR MELTING IS THE REGENERATIVE FURNACE, WHICH NORMALLY RELIES ON NATURAL GAS BURNERS HEATING THE GLASS POOL FROM THE OUTSIDE. THE EFFICIENCY OF THE PROCESS IS SOMEWHERE BETWEEN 15 TO 25 PERCENT. APPROXIMATELY 6.7 MILLION BTU'S PER TON IS REQUIRED TO MELT GLASS IN A HIGH-PRODUCTION GAS FURNACE, AND 12.3 MILLION BTU'S IN A LOW-PRODUCTION GAS FURNACE.

ELECTRIC MELTING, ON THE OTHER HAND, IS BASED ON THE TRANSFER OF ELECTRICITY BETWEEN ELECTRODES SUBMERGED IN THE GLASS MELT. THE BATCH IS HEATED FROM THE CENTER, PRODUCING VERY LITTLE HEAT LOSS. THERMAL EFFICIENCY RATINGS ARE TYPICALLY ABOUT 65 PERCENT. ONLY ABOUT 2.7 MILLION BTU'S PER TON ARE REQUIRED FOR THIS PROCESS IN A LARGE ELECTRIC MELTER, AND ABOUT 5.1 MILLION BTU'S PER TON FOR A SMALL ELECTRIC FURNACE. THIS IS A REDUCTION IN THERMAL ENERGY REQUIREMENTS OF 40.3 PERCENT AND 41.5 PERCENT, RESPECTIVELY.

ADDITIONAL ELECTROTECHNOLOGIES THAT ARE MORE EFFICIENT THAN TECHNOLOGIES USING OTHER FUEL SOURCES INCLUDE: ELECTRIC ARC FURNACES, INDUCTION HEATING, PLASMA-FIRED TECHNOLOGY, AND FREEZE

CONCENTRATION IN THE FOOD, CHEMICAL, PETROLEUM AND PAPER INDUSTRIES. THE REPORT ATTACHED TO MY TESTIMONY PROVIDES DETAILS ON EACH. THE REPORT CLEARLY OUTLINES THE POSITIVE ROLE THAT ELECTRICITY CAN PLAY IN REDUCING CONCENTRATIONS OF CO2 IN OUR ATMOSPHERE.

OVERALL, WE BELIEVE IT TO BE POOR PUBLIC POLICY TO SET ARBITRARY LIMITS ON THE USE OF ELECTRICITY IN THE MISTAKEN ASSUMPTION THAT AN INCREASE IN ELECTRICITY DEMAND WILL AUTOMATICALLY MEAN AN INCREASE IN ATMOSPHERIC POLLUTANTS. WE FEEL STRONGLY THAT LEGISLATION DRAFTED BY THE COMMITTEE SHOULD BE EXPLICIT AND CLEAR IN ITS LANGUAGE ON THIS POINT. IMPROVEMENTS IN ENERGY EFFICIENCY MUST NOT BE LIMITED BY DEFINITION TO ONLY THOSE ACTIONS WHICH REDUCE ELECTRIC ENERGY CONSUMPTION.

IN FACT, AS THE ATTACHED STUDY INDICATES, EFFICIENCY CAN BE IMPROVED AND ENVIRONMENTAL IMPACTS REDUCED BY SELECTIVE APPLICATION OF MODERN ELECTROTECHNOLOGIES IN SUBSTITUTION FOR OLDER, FOSSIL-FUELED TECHNOLOGIES. AMERICAN INDUSTRIES CAN IMPROVE THEIR COMPETITIVE POSITION IN THE INTERNATIONAL MARKETPLACE THROUGH SUCH SUBSTITUTION, AND THEY SHOULD BE ENCOURAGED TO DO SO. LEGISLATION SHOULD RECOGNIZE THAT AN INCREASE IN ELECTRICITY CONSUMPTION CAN PROTECT OUR ENVIRONMENT, IN KEEPING WITH THE GOALS OF THE COMMITTEE.

CFC PHASEOUT EFFECTS ON ENERGY USE

AN ADDITIONAL ISSUE AFFECTING BOTH ENERGY EFFICIENCY AND THE GLOBAL ENVIRONMENT IS ASSOCIATED WITH THE SEARCH FOR REPLACEMENTS

FOR CHLOROFLUOROCARBONS, OR CFC'S. AS YOU KNOW, THE SENATE RATIFIED THE MONTREAL PROTOCOL ON SUBSTANCES THAT DEPLETE THE OZONE LAYER BY A VOTE OF 89 TO 0. THE PROTOCOL CALLS FOR WORLDWIDE PRODUCTION OF CFC'S TO BE CUT IN HALF BY 1998, AND THE PRESIDENT HAS CALLED FOR A TOTAL BAN BY THE YEAR 2000.

THERE IS UNCERTAINTY AS TO THE IMPACT OF CFC REPLACEMENT ON ENERGY USE. IF THE EQUIPMENT DESIGNED TO FUNCTION WITHOUT CFC'S IS LESS ENERGY EFFICIENT THAN CURRENT DEVICES, ENERGY CONSUMPTION WILL RISE, BUT WITH NONE OF THE EFFICIENCY OR PRODUCTIVITY BENEFITS ASSOCIATED WITH SWITCHING TO ELECTROTECHNOLOGIES. WHILE MUCH WORK IS BEING DONE IN AN ATTEMPT TO SOLVE THE PROBLEM, THERE IS NO GUARANTEE OF A CFC SUBSTITUTE WHICH DOES NOT CARRY SOME KIND OF ENERGY PENALTY, IN EITHER PRODUCTION OR OPERATION. THUS, A MEASURE INTENDED TO PROTECT THE ENVIRONMENT CAN RESULT IN INCREASED ENERGY USE. EFFECTIVE LEGISLATION MUST RECOGNIZE THIS FACT EXPLICITLY.

INDUSTRY CONCERNS WITH S. 324

TURNING TO THE LEGISLATION BEFORE THIS COMMITTEE, IT IS OUR UNDERSTANDING THAT, AS WITH S. 324, THE LEGISLATION UNDER CONSIDERATION WOULD SEEK TO AMEND THE FEDERAL POWER ACT AND THE PUBLIC UTILITY REGULATORY POLICIES ACT SO AS TO CREATE LEAST-COST INVESTMENT STANDARDS, QUALIFYING CONSERVATION, AND QUALIFYING CONSERVATION ENTITIES. SUCH AMENDMENTS WOULD ALSO REQUIRE STATE REGULATORY COMMISSIONS TO CONDUCT HEARINGS EITHER TO ADOPT LEAST-COST STANDARDS OR TO PUBLICLY STATE THEIR REASONS FOR NOT ADOPTING SUCH STANDARDS.

LEAST-COST PLANNING

WITH RESPECT TO LEAST-COST PLANNING, THERE HAS BEEN MUCH PROGRESS IN THIS AREA. FURTHER, WHAT IS APPROPRIATE FOR LEAST-COST PLANNING VARIES WITH THE INDIVIDUAL CIRCUMSTANCES OF EACH UTILITY. WHAT MAY WORK FOR A SUMMER PEAKING UTILITY MAY BE INAPPROPRIATE FOR A WINTER PEAKING UTILITY. THUS, UTILITY SPECIFIC, RATHER THAN GENERIC FEDERAL, GUIDELINES ARE REQUIRED.

THIS KIND OF PLANNING IS NOW OCCURRING. I WOULD AGAIN CALL TO THE COMMITTEE'S ATTENTION THAT 43 OF THE 50 STATE REGULATORY COMMISSIONS ARE ALREADY ACTIVELY ENGAGED IN THE PROCESS OF DETERMINING THE MOST APPROPRIATE "LEAST-COST PLANS" FOR THEIR UNIQUE CIRCUMSTANCES. THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS AND INDUSTRY ASSOCIATIONS HAVE SUPPORTED THE DEVELOPMENT OF LEAST-COST PLANNING THROUGH: SEMINARS AND RESEARCH ACTIVITIES, NEW CONCEPTS SUCH AS PROVIDING FINANCIAL INCENTIVES FOR UTILITY DEMAND-SIDE PROGRAMS AND THROUGH IMPROVED UNDERSTANDING OF PROPER PRICING APPROACHES FOR DEMAND-SIDE MEASURES.

IN THE ABSENCE OF ANY FINDING THAT THESE EFFORTS ARE INADEQUATE IN SOME FASHION, OR ARE OTHERWISE FATALLY FLAWED, WE QUESTION THE NEED FOR FEDERAL LEGISLATION WHICH WOULD REQUIRE THAT ENTIRE COSTLY AND TIME-CONSUMING PROCESS TO BE REPEATED. SUCH A FEDERAL MANDATE WOULD ONLY SERVE TO DELAY THE IMPLEMENTATION OF SUCH PLANS AS HAVE BEEN OR ARE NEARING COMPLETION UNTIL A FURTHER FORMAL DETERMINATION COULD BE MADE ABOUT WHETHER THOSE PLANS MEET THE PRESCRIPTIVE FEDERAL STANDARDS SET FORTH IN THE PROPOSED

LEGISLATION.

DEMAND-SIDE MANAGEMENT

THE PORTIONS OF S. 324 WHICH WOULD ESTABLISH QUALIFYING CONSERVATION FACILITIES ADDRESS AN ISSUE RELATED TO, BUT DISTINCTLY DIFFERENT FROM, LEAST-COST PLANNING. WE AGREE THAT COST-EFFECTIVE DEMAND-SIDE MANAGEMENT (DSM) PROGRAMS SHOULD BE ENCOURAGED, AND THE EFFECTS OF DSM SHOULD BE INCORPORATED INTO THE PLANNING PROCESS. HOWEVER, WE OPPOSE THE TREATMENT OF DSM AS A SUPPLY RESOURCE.

THERE IS A FUNDAMENTAL ECONOMIC DIFFERENCE BETWEEN DEMAND-SIDE AND SUPPLY-SIDE MEASURES THAT MUST BE RECOGNIZED IN ANY ANALYSIS OF RELATIVE COST-EFFECTIVENESS: CUSTOMERS ALREADY HAVE AN INCENTIVE, EQUAL TO ELECTRICITY'S RETAIL PRICE, TO "PRODUCE" SAVED KILOWATTS OR KILOWATT-HOURS. AS I INDICATED PREVIOUSLY, MANY CUSTOMERS HAVE REDUCED THEIR DEMAND IN RESPONSE TO PRICE AND OTHER FACTORS, INCLUDING UTILITY EFFORTS TO PROMOTE CONSERVATION AND EFFICIENCY. IF, IN ADDITION TO A FOREGONE RETAIL SALE, A UTILITY PAYS FULL AVOIDED SUPPLY COST FOR SAVED CAPACITY OR ENERGY, AND THE RETAIL PRICE IS NOT MUCH DIFFERENT FROM AVOIDED COST, THEN THE TOTAL COST BEING INCURRED BY THE UTILITY FOR SAVED CAPACITY OR ENERGY WOULD BE ABOUT TWICE AVOIDED COST. IN EFFECT, THE UTILITY WILL PAY FOR SAVED ELECTRICITY TWICE THE PRICE IT WOULD HAVE RECEIVED FOR ELECTRICITY THAT WAS USED. THAT IS HARDLY A WAY TO ENCOURAGE ECONOMIC EFFICIENCY.

THE INDUSTRY IS EXTREMELY CONCERNED OVER THE CONCEPT OF QUALIFYING CONSERVATION ENTITIES FOR THE SAME REASONS AS THE

FEDERAL WITNESSES WHO APPEARED BEFORE THIS COMMITTEE ON OCTOBER 26, 1989. QUALIFYING CONSERVATION IS DEFINED IN SECTION 312 OF S. 324 AS "ANY REDUCTION AT ANY TIME IN THE DEMAND FOR ELECTRIC ENERGY BY THE CUSTOMERS OF A UTILITY, WHICH REDUCTION WOULD NOT OCCUR BUT FOR PAYMENTS RECEIVED BY A QUALIFYING CONSERVATION ENTITY..." ONE CONCERN IS THAT THE DEFINITION CAN BE INTERPRETED TO INCLUDE REDUCTIONS ACHIEVED SIMPLY BY SWITCHING FROM ELECTRICITY TO OTHER FUEL SOURCES. FOR EXAMPLE, IT IS CONCEIVABLE, UNDER THAT PROVISION OF THE BILL, THAT A GAS UTILITY COULD FORCE AN ELECTRIC UTILITY TO PAY THE FULL COST OF A CUSTOMER CONVERSION FROM ELECTRICITY TO NATURAL GAS. WHILE SWITCHING FROM ELECTRICITY TO ANOTHER FUEL WILL REDUCE ELECTRICITY USE, IT IS NOT NECESSARILY ENERGY EFFICIENT, NOR WILL IT NECESSARILY LEAD TO A REDUCTION OF EMISSIONS.

OTHER ISSUES INCLUDE: HOW TO DEFINE COST EFFECTIVENESS; THE LEVEL AND USE OF FINANCIAL INCENTIVES SUCH AS REBATES; HOW TO ADDRESS ACTUAL VERSUS FORECASTED ENERGY SAVINGS; THE ADVANTAGES AND DISADVANTAGES OF USING THIRD-PARTY ENERGY SERVICE COMPANIES FOR PROGRAM DELIVERY; CONTROLLING FOR CHANGED OCCUPANCY, BEHAVIOR, WEATHER, AND RATE CHANGES OVER TIME; HOW TO VERIFY PROGRAM PARTICIPATION; DEALING WITH CHANGES TO PROGRAMS AS THEY EVOLVE FROM YEAR TO YEAR; AND HOW TO QUANTIFY THE ENVIRONMENTAL BENEFITS AND COSTS OF DEMAND-SIDE PROGRAMS.

J. STEVEN HEROD OF THE FEDERAL ENERGY REGULATORY COMMISSION, IN HIS RECENT TESTIMONY BEFORE THIS COMMITTEE, EMPHASIZED THE DIFFICULTIES OF VERIFICATION AND OTHER REASONS WHY QUALIFYING

CONSERVATION WOULD PRODUCE COMPLEXITIES FAR BEYOND THOSE UNDER THE EXISTING QUALIFYING FACILITIES PROGRAM UNDER PURPA.

DURABILITY OF SAVINGS

THE SUGGESTED REVISIONS TO THE PUBLIC UTILITY REGULATORY POLICIES ACT AND THE FEDERAL POWER ACT BOTH PRESUME THAT DEMAND-SIDE AND SUPPLY-SIDE INVESTMENTS CAN BE TREATED WITH EQUAL CERTAINTY FROM A RELIABILITY STANDPOINT. IN SHORT, A KILOWATT OF DEMAND REDUCTION IS TREATED AS IF IT WERE AS CERTAIN TO EXIST OVER TIME AS WOULD BE A KILOWATT OF ADDED CAPACITY. EXPERIENCE, HOWEVER, SHOWS THIS TO BE AN UNFOUNDED ASSUMPTION.

WHILE A KILOWATT OF INSTALLED GENERATING CAPACITY REMAINS RELATIVELY CONSTANT OVER THE LIFE OF THE PLANT, THE SAME CANNOT BE SAID OF A KILOWATT OF CONSERVATION. FOR EXAMPLE, THE ALLIANCE TO SAVE ENERGY, UNDER CONTRACT TO THE U.S. DEPARTMENT OF ENERGY, RECENTLY COMPLETED A STUDY OF SIXTY HOMES IN WISCONSIN AND MAINE WHICH MEASURED THE PERSISTENCE OF ENERGY SAVINGS OVER TIME. IN THE EARLY 1980'S, THESE HOMES HAD THEIR OIL HEATING SYSTEMS UPGRADED WITH A NEW, HIGH-EFFICIENCY, FLAME RETENTION BURNER AT A TYPICAL COST OF $500. THE ALLIANCE'S STUDY SHOWED THAT "ON AVERAGE ABOUT ONE-THIRD OF THE INITIAL STEADY-STATE EFFICIENCY WAS LOST OVER THE FIVE YEAR PERIOD." POORLY PERFORMED MAINTENANCE--OR NO MAINTENANCE AT ALL--APPEARED TO BE THE PRIMARY CAUSE FOR THE DEGRADATION IN PERFORMANCE. IN FACT, THE STUDY NOTED THAT A MERE 16 PERCENT OF THE INSTALLATIONS RECEIVED REGULAR MAINTENANCE, WHILE SOME 46 PERCENT OF THE UNITS WERE NEVER SERVICED AT ALL AFTER INSTALLATION.

ENGINEERING EVALUATIONS HAD SHOWN THAT INSTALLING A NEW BURNER WOULD IMPROVE THE HEATING SYSTEM'S EFFICIENCY BY SOME 20 PERCENT. BUT IN ONLY FIVE YEARS TIME, THE STUDY OBSERVED AN ACTUAL IMPROVEMENT OF ONLY 13.2 PERCENT, ON AVERAGE. IT CAN REASONABLY BE ASSUMED, GIVEN NO CHANGE IN THE MAINTENANCE HABITS OF THE HOMEOWNERS, THAT FURTHER DEGRADATIONS IN PERFORMANCE WILL OCCUR OVER TIME.

WHAT THE STUDY ILLUSTRATES IS THE UNCERTAINTY ASSOCIATED WITH DEMAND-SIDE EFFICIENCY IMPROVEMENTS. TO BE SURE, SAVINGS STILL REMAIN, AND BETTER MAINTENANCE HABITS MIGHT WELL RESTORE SOME OF THE LOST GAINS. BUT HAD THE 20 PERCENT IMPROVEMENT BEEN CONSIDERED A RESOURCE AS DICTATED BY THE LANGUAGE OF S. 324, A CAPACITY SHORTFALL WOULD HAVE OCCURRED IN THE SHORT PERIOD OF ONLY FIVE YEARS.

TREATMENT OF EFFICIENCY IMPROVEMENTS IN RESOURCE PLANNING

IT IS FOR REASONS SUCH AS ARE ILLUSTRATED BY THE ALLIANCE STUDY THAT ELECTRIC UTILITY PLANNERS PREFER TO TREAT ENERGY EFFICIENCY IMPROVEMENTS AS A REDUCTION IN THE FORECASTED DEMAND RATHER THAN TO EQUATE THE IMPROVEMENTS WITH ACTUAL GENERATING CAPACITY INSTANTLY AVAILABLE FOR CUSTOMER NEEDS. THIS DISTINCTION MAY APPEAR SOMEWHAT SUBTLE, BUT IT IS EXTREMELY IMPORTANT AND MUST NOT BE IGNORED.

TO UNDERSTAND THE IMPORTANCE OF THIS DISTINCTION, PUT YOURSELF IN THE PLACE OF A UTILITY PLANNER. YOUR JOB, REDUCED TO ITS ESSENCE AND OVERSIMPLIFIED, IS TO KEEP THE LIGHTS ON AT THE LOWEST

REASONABLE FINANCIAL AND ENVIRONMENTAL COST. THE OBLIGATION TO SERVE IS AN ABSOLUTE REQUIREMENT, BOTH LEGALLY AND MORALLY.

AS A PLANNER, YOU KNOW THAT THE LOAD FORECAST IS ADJUSTABLE, EITHER UP OR DOWN, ON AN ANNUAL BASIS, ACCORDING TO YOUR BEST INFORMATION REGARDING SUCH THINGS AS DEMOGRAPHIC TRENDS, HOUSING SIZE, ECONOMIC GROWTH AND SO FORTH. YOU ALSO KNOW THAT A NEW BASE LOAD POWER PLANT TAKES 8-10 YEARS TO BUILD AND IS TERRIBLY EXPENSIVE. WHILE THE CONSTRUCTION SCHEDULE CAN BE STRETCHED OUT, IF NECESSARY, THERE IS LITTLE YOU CAN DO TO SHORTEN THAT CONSTRUCTION PERIOD. YOUR RESPONSIBILITY IS TO DETERMINE HOW MUCH POWER YOUR CUSTOMERS WILL REQUIRE AND WHEN THEY WILL REQUIRE IT, AND TO BE CERTAIN YOU HAVE ENOUGH CAPACITY TO SUPPLY THOSE NEEDS, WITH SOME IN RESERVE FOR EMERGENCIES AND SO FORTH. IF YOU MAKE A MISTAKE, AND FAIL TO ACHIEVE THIS INTRICATE BALANCING OF LOADS AND RESOURCES, ONE OF TWO THINGS WILL HAPPEN, BOTH OF WHICH ARE BAD BUT ONE OF WHICH IS DOWNRIGHT DISASTROUS.

IF YOUR CUSTOMERS DON'T REQUIRE AS MUCH AS YOU THOUGHT THEY MIGHT, YOU MAY HAVE BUILT TOO MUCH. YOU MIGHT HAVE SURPLUS CAPACITY, BUT THE LIGHTS STAY ON. AT THE WORST, THERE MAY BE REPERCUSSIONS FOR THE COMPANY'S FINANCES (AS WELL AS YOUR CAREER).

ON THE OTHER HAND, IF YOUR CUSTOMERS REQUIRE MORE THAN YOU FORECAST, YOU MIGHT NOT HAVE BUILT ENOUGH. IF THE LIGHTS GO OUT, THE POSSIBLE RESULTING ECONOMIC AND SOCIAL DISRUPTION COULD BE STAGGERING. WORSE YET, IT COULD WELL TAKE THE FULL CONSTRUCTION PERIOD BEFORE THE SITUATION COULD BE RECTIFIED. IN SHORT, YOU HAVE NO CHOICE BUT TO BE SURE THAT SUFFICIENT CAPACITY WILL BE THERE

WHEN YOUR CUSTOMERS NEED IT.

A MANDATORY REQUIREMENT TO PURCHASE QUALIFYING CONSERVATION WOULD DISTORT THE PLANNING PROCESS, REDUCE MANAGEMENT FLEXIBILITY IN RESPONDING TO AN UNCERTAIN FUTURE, AND WILL NOT ACHIEVE THE ECONOMIC EFFICIENCIES DESIRED FROM THE LEGISLATION. THE ECONOMIC EVALUATION OF DEMAND-SIDE PROGRAMS MUST BE INTEGRATED WITH THE SUPPLY-SIDE PLANNING PROCESS TO ENSURE RELIABLE, FLEXIBLE, AND ECONOMICALLY EFFICIENT RESOURCE STRATEGIES DESIGNED FOR THE SPECIFIC CHARACTERISTICS OF EACH UTILITY. THE EXISTING MIX OF GENERATING UNITS, FUEL CONTRACTS, ENVIRONMENTAL CONTROL STRATEGY, LOAD SHAPE, AND FUTURE ECONOMIC ACTIVITY SHOULD ALL PLAY A ROLE IN DETERMINING THE SIZE, TYPE, TIMING, AND BALANCE BETWEEN SUPPLY AND DEMAND-SIDE RESOURCES. OBVIOUSLY, AN OVERLY PRESCRIPTIVE NATIONAL MANDATE CANNOT APPROPRIATELY MEET THE NEEDS OF EACH INDIVIDUAL UTILITY, AND WILL PROBABLY RESULT IN PURCHASING UNECONOMICAL, SO-CALLED CONSERVATION.

UTILITIES MUST MAINTAIN THE RIGHT TO DEVELOP SPECIFIC OBJECTIVES FOR THEIR TOTAL DEMAND-SIDE MANAGEMENT PROGRAM, EVALUATE EACH ALTERNATIVE INDIVIDUALLY AND IN COMBINATIONS, DETERMINE THE APPROPRIATE FINANCIAL REQUIREMENTS AND INCENTIVES REQUIRED TO ACHIEVE THE DESIRED LEVEL OF RESULTS, AND DEVELOP SPECIFIC MARKETING AND MONITORING PROGRAMS TAILORED FOR EACH PROGRAM. BUT, ABOVE ALL, UTILITIES MUST HAVE THE FLEXIBILITY TO CHANGE THEIR STRATEGIES AND FINANCIAL COMMITMENTS IF PROJECTED DEMAND REDUCTIONS ARE NOT ACHIEVED. THIS POINT IS HIGHLIGHTED IN THE ALLIANCE TO SAVE ENERGY STUDY THAT INDICATED ONE-THIRD OF THE EFFICIENCY

IMPROVEMENT WAS LOST IN THE FIRST FIVE YEARS.

ONCE THE HUMAN FACTOR IS ENTERED INTO THE EQUATION, UNCERTAINTY LOOMS LARGE. IN THE CASE OF THE ALLIANCE STUDY, THE PROBLEM SEEMS TO BE LACK OF PROPER MAINTENANCE. HOWEVER, OTHER HUMAN FACTORS CAN INFLUENCE THE PERFORMANCE OF AN EFFICIENCY IMPROVEMENT AS WELL. FOR INSTANCE, NOTHING CAN ALTER A PATTERN OF LIVING AND PATTERNS OF ENERGY CONSUMPTION FASTER OR MORE DRAMATICALLY THAN THE ARRIVAL OF AN INFANT. HIGHLY VARIABLE, HUMAN FACTORS CAN MORE EASILY BE ACCOMMODATED AS A PART OF AN INTEGRATED RESOURCE PLAN BASED ON A UTILITY'S SPECIFIC REQUIREMENTS. MANDATORY OBLIGATIONS TO PURCHASE CONSERVATION CANNOT ACCOMMODATE THESE VARIABLES.

CONCLUSION

FINALLY, WE REPEAT OUR CONCERN WITH THE LANGUAGE OF S. 324 ESTABLISHING A NEW CLASS OF "CONSERVATION ENTITIES" TO BE TREATED THE SAME AS QUALIFYING FACILITIES UNDER PURPA. OUR CONCERN CENTERS ON THE ISSUE OF WHETHER A KILOWATT SAVED IS DIRECTLY EQUAL TO A KILOWATT GENERATED. IT IS NOT. AS WE HAVE EMPHASIZED EARLIER, SUPPLY SOURCES ARE PROVIDED TO MEET CUSTOMERS' NEEDS INSTANTANEOUSLY UPON DEMAND AND OVER THE LONG TERM. THE CONTRIBUTION OF CONSERVATION AND OTHER DEMAND-SIDE RESOURCES IS NOT PREDICTABLE ENOUGH TO MEET THE NEED. THE LEAST-COST PROVISIONS UNDER CONSIDERATION CREATE A FEDERALLY MANDATED INCENTIVE PAYMENT FOR CONSERVATION BASED ON A UTILITY'S AVOIDED COSTS. HOWEVER, THAT WOULD IGNORE, AND IN MANY CASES DISRUPT, THE SIGNIFICANT POSITIVE

STEPS THAT UTILITY COMMISSIONS ARE UNDERTAKING TO TAILOR PROGRAMS WHICH DIRECTLY ADDRESS THE LOCAL NEEDS AND CIRCUMSTANCES OF INDIVIDUAL UTILITIES, AND THE STATE'S PARTICULAR REQUIREMENTS. MOREOVER, IT IS UNCLEAR HOW THE PROPOSAL COULD BE IMPLEMENTED EFFECTIVELY, AND WHETHER IT WILL PRODUCE BENEFITS FOR ELECTRIC CONSUMERS GREATER THAN THE PROGRAMS CURRENTLY IN PROCESS THROUGHOUT THE NATION. THEREFORE, WE BELIEVE THE BEST POLICY POSITION IS TO ALLOW UTILITIES, WORKING WITH THEIR STATE COMMISSIONS, TO DETERMINE HOW DEMAND-SIDE OPTIONS SHOULD BE INCLUDED IN THE PLANNING PROCESS, RATHER THAN TO IMPOSE A FEDERAL STANDARD.

IN CONCLUSION, WE REITERATE OUR COMMITMENT TO INCREASING OUR NATION'S ENERGY EFFICIENCY. WHILE WE DISAGREE WITH PARTICULAR ASPECTS OF THE PROPOSED LEGISLATION AS INDICATED IN THIS TESTIMONY, WE DO AGREE THAT RATIONAL PUBLIC POLICY SHOULD AND CAN BE CRAFTED TO ADDRESS APPROPRIATELY THE ISSUE OF POTENTIAL GLOBAL CLIMATE CHANGE. OUR INDUSTRY STRONGLY SUPPORTS ENERGY POLICIES THAT ENCOURAGE RESEARCH, INTERNATIONAL COOPERATION AND THE DEVELOPMENT OF A DIVERSITY OF ENERGY SOURCES. THANK YOU, MR. CHAIRMAN AND MEMBERS OF THE COMMITTEE, FOR THIS OPPORTUNITY TO PRESENT OUR INDUSTRY'S VIEWS. WE WISH YOU SUCCESS IN YOUR DELIBERATIONS, AND STAND READY TO ASSIST IN ANY WAY WE CAN.

APPENDIX A

TESTIMONY OF WILLIAM MCCOLLAM, JR.
President, Edison Electric Institute
Before The
UNITED STATES SENATE
ENERGY & NATURAL RESOURCES COMMITTEE

Good morning ladies and gentlemen. My name is William McCollam, Jr. I am President of the Edison Electric Institute (EEI), the association of the nation's investor-owned electric utilities. Our industry is pleased to be afforded the opportunity of presenting our views on S. 324 which addresses many complex issues which have profound significance not only for our customers and our nation but for all the peoples of our planet. The industry would like to offer its commendation to Congress and this Committee for their efforts to gather facts and information on this most complex issue prior to selecting a public policy designed to ensure the protection of the Earth's environment.

The greenhouse effect is real. It exists. It is the reason we are able to live on our planet in relative comfort. Its existence is not in question. What is of concern is that certain societal activities may result in a significant change in the current global climate. To link any potential changes in this climate with the hot summer and drought of 1988 is not scientifically supportable. However, the electric utility industry does not intend to ignore the possibility that a warming trend may be occurring.

The Earth's temperature represents a balance between incoming solar energy and outgoing infrared radiation. The Earth's temperature is influenced by several factors including the retention of some of the heat by atmospheric gases. It is possible that an increase in concentration of atmospheric gases which absorb the outgoing infrared radiation could result in a rise in average global temperature. Such increases these gases, such as carbon dioxide (CO_2) concentration are occurring. Similarly, other greenhouse gases are increasing in the troposphere. Over the past century, data indicate an increase of about 0.5 degrees Centigrade in mean global temperature but, because of climatological variability, we are not sure if the change is within the range of normal oscillations. A continued increase in concentration of these greenhouse gases, however, could raise the mean global temperature by 2 to 5 degrees Centigrade within the next century or so.

A number of gases in the atmosphere can serve as absorbers of infrared radiation. To date, CO_2 has received the most attention.

- In addition to CO_2, other greenhouse gases are receiving attention. Among these are nitrous oxide, methane and chlorofluorocarbons (CFCs).

Some scientists speculate that a rise in average global temperature of 4 or 5 degrees Centigrade could mean climate changes with serious societal implications. Admittedly, we are not certain what climatic changes would take place. However, we can expect that such changes could have significant effects on agriculture, rainfall, hydrology, sea level, storm events, demography and human health.

Although we can envision a multitude of serious consequences to society, we must recognize that our knowledge is currently so limited that we cannot yet judge with any accuracy what might be the results of continued increases in greenhouse gases. We are hampered by two major uncertainties: the global carbon cycle and the modeling of global climate.

Predicting what sort of temperature changes might face the planet over the next century or so depends on several factors including the knowledge of future atmospheric concentrations of greenhouse gases. Future CO_2 levels depend on factors which, at best, are difficult to quantify such as land use, atmospheric retention of emitted CO_2, fuel use and energy growth. These contributing factors, in turn, are dependent on others, most of which are fraught with a high degree of uncertainty.

Essential to any projection of atmospheric CO_2 concentrations is future energy use. From the end of World War II until 1973, world energy use had increased at a rate of about 5% per year. Few who study the CO_2 issue, however, envision a continuation of such a high growth rate. Projections to the year 2000 range from a high of nearly 4% per year to a low of near zero. Projections into the middle of the 21st Century show a similarly wide spread of values, with most estimates at about 2.5% per year. Such wide divergence should surprise none inasmuch as the projection of energy use is based on major uncertainties and the farther out such projections are made, the greater the level of uncertainty. We must, therefore, view any estimate of energy use for the 21st Century with a great deal of skepticism.

All of this is not to suggest that rational public policy cannot be crafted to address the issue. We strongly advocate a holistic approach to the issue. Our industry strongly supports rational energy policies that address global environmental issues by encouraging international cooperation and by contributing to the development of a diversity of energy sources.The industry is aggressively pursuing several paths which are designed to meet the nation's energy needs while reducing atmospheric emissions. In fact, we are in the process of preparing a set of policy recommendations to be released shortly and a good many of these recommendations are consistent with the approach taken in various sections of S. 324. While most of the report focuses on future capacity needs, the recommendations presented are entirely consistent with the extensive efforts by electric utilities to promote energy efficiency. In this report, the promotion of energy efficiency as a matter of national policy in all sectors of the economy is given first priority. It is important to underscore--in the strongest possible terms--that this industry, its customers and its regulators have combined to achieve substantial improvements in the efficient production and use of electricity and, that energy efficiency plays a crucial role in our industry's strategies for an adequate, reliable, affordable and environmentally sound electricity supply for the future.

The history of this industry clearly demonstrates our long term commitment to energy efficiency. As an example, the number of utility-sponsored programs designed to increase customer end-use efficiency has increased from about 134 in 1977 to nearly 1300 today. These efforts cover all market sectors in a wide variety of ways. They range from the provision of informational materials for customer use to direct control of customer loads. They run the gamut from mass media advertising to on-site energy audits. They include incentives ranging from alternative pricing structures to direct cash rebate payments for the purchase of high efficiency end-use equipment, zero or below market interest rate financing of efficiency improvements, shared savings programs, direct marketing of new efficiency technologies, construction design assistance and guidelines, irrigation pump testing, re-lamping programs and many others. This listing is incomplete but is, nevertheless, illustrative of the broad range of activities by which we aggressively seek to improve energy efficiency. The electric utility industry now spends in excess of $1 billion per year in support of these efforts and the amount continues to increase.

The result of these efforts is no less impressive. The capacity savings which are a direct result of these efforts since 1977 are estimated at more than 21,000 megawatts to date and are projected to exceed 45,000 megawatts by the year 2000. If one were to assume a very conservative construction cost for new capacity of $1,000 per kilowatt, this means that something on the order of $21 Billion of new investment has been avoided so far and as much as $45 Billion will be saved by the year 2000.

By any rational standard of judgement, this record ofaccomplishment is indicative of a serious and long term commitment to energy efficiency. Further, electric utilities continue to work closely with our state regulatory commissions and our customers to find ways in which energy efficiency and load management programs can be improved. This means development of new and more efficient end-use applications as is done at the Electric Power Research Institute backed by industry-wide funding. It means our industry's continued support for such sensible legislation as the National Appliance Energy Conservation Act of 1987 to produce greater gains in efficiency. It means continued support from state commissions to permit utilities the flexibility to conduct pilot programs tailored to local needs which hold the promise of an increased range of services available to customers in all market segments. It means the adoption of such model energy codes as the one recently promulgated by the Council of American Building Officials for new construction. Finally, it means sound public policy in light of growing public concern over possible global climate change.

Conservation, the efficient use of fossil fuels, the development of renewable energy sources and use of nuclear power all must be considered simultaneously as there is no one single answer which satisfactorily addresses issues of global climate change, energy supply, security, international competitiveness, economic health, efficiency, productivity and the quality of life. Policies which solve one problem at the expense of another should not be tolerated. For example, to mandate flue gas scrubbers to remove sulfur dioxide (SO_2) would increase emissions of CO_2.

In 1988, less than 8% of the world's CO_2 was emitted by the U.S. utility industry. If we were to assume that this level went to zero immediately, the result would be that the much-discussed doubling of CO_2 in the atmosphere to the 600 parts per million level would be slowed by some 3 to 5 years. On the scale most frequently discussed, 50 to 100 years, this delay is almost inconsequential. Based on the results of an admittedly extreme case not contemplated by S.324, we believe that any plan calling for urgent and extreme action to reduce utility CO_2 emissions is premature at best. We believe it proper to advocate increased electrification, conservation and energy efficiency while continuing to increase our scientific knowledge base on the issue.

We are not suggesting inaction. Quite the contrary. There is much in this bill worthy of support and implementation. There are some provisions of the bill which merit further scrutiny. For example, in order to attempt a 20% reduction in CO_2 emissions, the bill envisions the creation of a National Least-Cost Energy Plan by the Secretary of Energy and the Administrator of the Environmental Protection Agency in a scant 18 months. The content of the Plan as described in the proposed legislation is exhaustive to put it mildly. According to a recently published study by the Electric Power Research Institute, electric resource planner is nearly every state either now use or are actively considering some form of what has become known as Least-Cost Planning. At least 43 states have functioning strategies in this area or are considering, developing or implementing a process designed to attempt to find the most cost-effective mix of new generating facilities and demand side management. It is an understatement to say that this complex and difficult work has taken much time and treasure and yet the definition of the term "least-cost" is still a matter of much debate and discussion with at least as many definitions as there are debaters. The proposed legislation is silent on this matter. We would support the development of a national energy plan which suggests an appropriate balancing of supply, demand, financial and environmental concerns but believe Tittle I of the bill could use much more refinement and a more reasonable time frame.

The section of the bill calling for a reduction in energy use per unit of GNP of 2 to 4% PER YEAR through 2005 should be revisited. On the surface, this does not sound like such a terribly large reduction. Upon closer examination, however, it turns out to be a staggering amount of energy. Assuming all goes according to the timetables laid out in the bill, the reductions would have to begin in 1991. At the 2% rate of reduction, energy use per unit of GNP would have to be down by a total of 32% by 2005 and at the 4% rate, energy use per unit of GNP would have to be down by some 73%. By comparison, from 1973 to 1988 energy use per unit of GNP declined by 27%. One either has to assume energy use will remain unchanged and the economy will expand wildly which is hardly sound reasoning, or one must assume a near tripling of energy efficiency by this measure which suffers the same deficiency. In any case, this provision is simply unrealistic.

For some years now, federal state and local governments along with energy suppliers of all types have struggled with the concept of some sort of residential energy rating system which could be applied fairly to all residential housing units, both new and old. The effort has been notable in its lack of success. Aside from fuel bias, perhaps the most thorny problem has been the application of the various systems to existing structures. Unfortunately, the costs associated with bringing an older residence up to new specifications are generally very high and the market for such residences generally consists of those with limited means. The result is a kind of de facto "red-lining" which has the unintended effect of discrimination. Clearly more work must be done in this area but there is no reason to delay adoption of a standard for new construction. I earlier referenced our support for the recently promulgated Model Energy Code of the Council of American Building Officials. This consensus standard improves the energy efficiency of new structures when compared with the existing base. Under the provisions of Public Law 678, GSA, DOD, HUD and DOE are all scheduling rulemaking proceedings concerning the adoption of this Model Energy Code. Thus, a firm standard now exists for new construction and the process of adoption has begun. We would suggest that while work proceeds on a system for existing housing, adoption of this standard for new construction would be of immediate benefit.

Certain sections of the proposed legislation would amend the Federal Power Act and the Public Utility Regulatory Policies Act so as to create least-cost investment standards, qualifying conservation and qualifying conservation entities. Our industry's position here is one of concern that consumers do not end up paying twice for conservation and demand reductions. Customers installing conservation or load management equipment receive an immediate benefit from reduced power consumption and a corresponding reduction in the cost of electricity. In addition as I mentioned earlier, utilities often encourage such actions by making a one-time payment to customers installing such equipment or offering very favorable financing terms. It would be inappropriate to consider demand side measures a second time as part of an all source competitive bidding. Consideration of the level and type of demand side subsidies to customers necessarily involves a cost-benefit analysis and assessment of the impact on participating and non-participating customers. Utilities make these assessments, often under state commission guidelines. In system planning, it is customary to treat the load impacts of demand side measures as deductions from a load forecast made without assuming new demand side measures. This procedure avoids confusing the utility's cost-benefit assessment with treating demand side megawatts as a direct substitute for supply side megawatts. We have strongly advised FERC against treating them as equivalent and would make the same recommendation here. We are also concerned that S.324 may permit qualifying facilities to compete as qualifying conservation entities. This raises serious conflict of interest concerns which could be detrimental to electric consumers and the general objectives of the bill. In addition, the bill would require utilities to purchase from qualifying conservation entities. We believe this will be unnecessary given the new PURPA standards created by the bill and its repeal of Section 216 of NECPA. It could lead to wasteful duplication of effort and increased cost to the customer. The provision should be amended to provide merely that state commissions may, to the extent they find it necessary to achieve the bill's conservation goals, require such purchases.

Finally, we would urge the federal government to promote and support international cooperation and to encourage all nations to take responsibility for safeguarding the Earth's environment. Acting alone will not significantly reduce future emissions. Dictating policy to developing countries is most certainly not the answer. Only by working together can we address this issue. Since any effects which might occur will be global, activity on the issue should be global as well. For our part, through EEI, the electric utility industry intends to open direct lines of communication with energy suppliers around the world to facilitate participation in programs designed to meet the growing energy demands while protecting the global environment.

Thank you, Mr. Chairman, for this opportunity to presentour views on this issue. We wish you success in your committee's deliberations and stand ready to assist in any way we can.

APPENDIX B

JULY 1989

CARBON DIOXIDE REDUCTION THROUGH ELECTRIFICATION OF THE INDUSTRIAL AND TRANSPORTATION SECTORS

For:
Edison Electric Institute
1111 Nineteenth Street, NW
Washington, DC 20036
202/778-6400

By:
Energy Research Group, Inc.
400-1 Totten Pond Road
Waltham, MA 02154
617/890-1730

EDISON ELECTRIC
INSTITUTE The association of electric companies

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EXECUTIVE SUMMARY

The electric utility industry as part of its on-going efforts to minimize environmental impacts has undertaken an assessment of the end-use opportunities to reduce carbon dioxide (CO_2) emissions. The electric utility industry is perceived to be the largest potential generator of global warming gases in the United States. This perception has led to the assumption that increasing electricity consumption cannot reduce global warming trends. The research discussed in this report, however, indicates that the assumption is incorrect. This report concludes that the use of highly efficient electric technologies in several traditionally fossil-fueled applications has the potential to reduce CO_2 emissions.

The higher efficiencies generally associated with electric end-uses could reduce CO_2 by decreasing overall energy use when compared with fossil-fueled processes. Since less energy is required to perform the same task, fossil fuel consumption can be reduced or eliminated, decreasing the amount of combustion products, including CO_2. Reductions in combustion products are dependent upon two factors: first, the relative technology efficiencies; and second, the mix of fossil and lower polluting non-fossil fuels used to generate electricity.

Our studies show that increased electrification of certain applications in the industrial and transportation sectors could reduce the amount of carbon dioxide generated nationally by fossil fuels by at least six percent. A number of commercially available and competitive electrotechnologies could be substituted for fossil fuel processes, resulting in a reduction of industrial CO_2 emissions by over 17 percent and transportation emissions by over eight percent. Reductions of other global gases and additional pollutants are possible as well, but have not been investigated as part of this report.

Introduction

Carbon dioxide is produced when fossil fuels are burned for electricity generation, transportation, and manufacturing purposes. Since CO_2 is estimated to represent approximately 50 percent of the gases contributing to potential global warming trends, it is the focus of this report. Other major gases identified as contributing to global warming include chlorofluorocarbons, methane, and nitrous oxide.

According to the United States Department of Energy (DOE), the electric utility industry produces approximately 35 percent of the total man-made CO_2 generated in the country. The transportation sector produces 32 percent, and the industrial sector 30 percent.

This study, which was conducted by the Energy Research Group, Inc., for the Edison Electric Institute focuses on ways to utilize existing high-efficiency electrotechnologies resulting in a net reduction in the nation's overall CO_2 production.

Summary of Results

Significant CO_2 reductions can occur by substituting electricity for fossil fuels in several industrial applications. By substituting the following electrotechnologies for comparable fossil-fueled processes, a minimum reduction of 17 percent in annual CO_2 generation from the industrial sector may be realized:

- electric arc furnace
- induction heating
- electric glass melting, annealing, conditioning
- infrared heating
- freeze concentration

Electrotechnologies are already gaining wide-spread acceptance within the industrial sector because of their high efficiencies, precise energy control capabilities, and high processing and production rates. The fact that they are CO_2 reducing, as well, should provide an added incentive for their development and use.

Electric modes of transportation also have CO_2 reducing potential. An 8.2 percent reduction in the total amount of CO_2 currently produced in the transportation sector could be realized from direct substitution of gas or diesel cars or buses with equivalent electric models, and cross substitution of more efficient electric modes of transit for less efficient fossil-fueled modes.

Additional research is needed to further quantify the CO_2 reductions of these and other potential CO_2 reducing technologies on a nationwide basis. The preliminary findings, however, provide a basis for future R&D and legislative efforts to reduce CO_2 through the use of highly efficient electric technologies.

The research effort was comprised of several steps, each of which is summarized below.

The Electric Utility Sector: Developing a Basis for Comparison

To compare CO_2 production in comparable fossil fuel and electric end-uses, the total amount of CO_2 produced by the utility sector in 1988 was calculated and an average "pounds of CO_2 per kilowatt-hour (kWh) generated" was estimated. Only direct CO_2 emissions from combustion were considered in the analysis. Indirect CO_2 emissions during fuel extraction and refining processes for coal, natural gas, and petroleum were not included.

In 1988, based on the national average fuel mix, 1.39 pounds of CO_2 were produced for every kWh generated. This amount is expected to remain almost constant over the next seven years with a slight decreasing trend due to increases in nuclear and hydroelectric generation and a trend towards gas-fired small power production facilities. The findings are based on the nation's average rather than marginal fuel mix for several reasons, the most important being that the mixes are similar. In the short term, natural gas and oil currently predominate throughout the country as marginal units. In the long term, according to the NERC and DOE projected 1997 fuel mix, the fuels used will generate slightly less CO_2 per kWh than the current mix. Thus, when the short and long term factors are considered, a trend exists that will reduce the amount of CO_2 generated to meet new electrification needs. The national average mix was also used to limit speculation on future marginal units, and to increase the study's usefulness on a national basis. As electric utility fuel mix compositions vary significantly by region, different levels of CO_2 generated per kWh are possible and need to be analyzed if individual region or utility specific impacts are to be evaluated.

In order to evaluate electrotechnology substitution potential in this analysis, CO_2 production for each fuel type on a BTU basis was evaluated. The results are provided below:

CO_2 Generated per BTU
Delivered from Various Fuels

Electricity - 3.9×10^{-4} lbs CO_2/BTU
Coal - 1.9×10^{-4} lbs CO_2/BTU
Oil - 1.7×10^{-4} lbs CO_2/BTU
Natural Gas - 1.2×10^{-4} lbs CO_2/BTU

These estimates were used to compare the CO_2 reducing potential of electrotechnologies in the industrial and transportation sectors. Although electricity is more CO_2 intensive than other fuels, power plant conversion losses have been taken into account, and many electric end-uses are significantly more energy efficient than comparable fossil-fueled processes, lowering total BTU requirements considerably.

The Industrial Sector:
Electrotechnologies that Can Reduce CO_2 Levels

Electrotechnology substitution possibilities were considered in those manufacturing industries that consume the largest amount of fossil fuels, and where it has been determined that electrification potential is the greatest. These include:

- the primary metals industry (SIC 33)
- the stone/clay/glass industry (SIC 32)
- the chemicals industry (SIC 28)
- the petroleum refining industry (SIC 29)
- the pulp and paper industry (SIC 26)
- the food industry (SIC 20)

Based on literature research, the following electrotechnologies were identified as having the greatest potential to reduce CO_2 levels:

- Primary Metals/Metals Processing Industry:
  - electric arc furnace
  - induction heating
  - induction melting
  - plasma-fired technology
  - infrared heating

- Stone/Clay/Glass Industry:
  - electric glass melting, conditioning, and annealing

- Food, Chemical, Petroleum and Paper Industries:
  - freeze concentration

Several other industrial electrotechnologies may have CO_2 reducing characteristics as well. However, this analysis was limited to the selection of seven technologies for detailed evaluation.

CO_2 reductions were found to exist in applications involving: electric arc furnace; induction heating; electric glass melting, conditioning, and annealing; freeze concentration; and infrared heating. Use of induction melting and plasma-fired cupola for foundry melting were not found to produce CO_2 savings, except in regions where significant quantities of these non-CO_2 producing fuels are used to generate electricity.

This analysis focused only on identifying CO_2 reductions when replacing existing fossil-fueled technologies with electric technologies, without evaluating in detail other advantages or disadvantages of electric substitution.

The results of the industrial analysis are summarized in Table E-1. Carbon dioxide reductions on a unit or process basis were calculated for most of the electrotechnologies. No attempt was made to assess the market penetration rates of most of the electrotechnologies because data is limited in this area. The rates provided were derived from research conducted by the Electric Power Research Institute (EPRI). Of those electrotechnologies for which industry-wide reductions were projected (i.e., the electric arc furnace and freeze concentration), CO_2 reductions represent about 17.4 percent of the total industrial sector's annual CO_2 emissions, or 4.1 percent of the total man-made CO_2 produced annually in the United States.

Transportation Sector: Impacts of Electric Transport

Two major areas of CO_2 reduction were evaluated in the transportation sector. The first was the direct substitution of electric powered vehicles for fossil-fueled vehicles, including automobiles, light trucks, trains and buses. The second was the cross substitution of more efficient electric modes of transit for less efficient fossil-fueled modes, such as electrified rail as an alternative for trucking containerized type shipments.

Total CO_2 production rates for each type of transport were estimated by deriving the energy requirements by type. The results are summarized in Table E-2. Conclusions drawn from this table are for the total technical potential. No attempt was made to assess the market penetration rates or market saturation rates of each electric substitute, as data is also limited in this area. Total savings for the modes evaluated represent 8.2 percent of transportation sector CO_2 emissions, or 2.6 percent of total CO_2 produced in the United States.

Impacts of Findings

This preliminary research effort identified a number of electrotechnologies and electric transport opportunities that have the potential to significantly reduce CO_2 production in the United States. These CO_2 reductions are achievable in most cases with existing, commercially competitive technologies.

The findings of this research can contribute to the continued development and promotion of highly efficient electrotechnologies not only to decrease the production of CO_2 and reduce other transportation and manufacturing pollutants, but also to increase industrial competitiveness.

TABLE E-1

SUMMARY OF CARBON DIOXIDE REDUCTIONS FROM ELECTROTECHNOLOGIES VERSUS COMPARABLE FOSSIL-FUELED PROCESSES BASED ON 1988 NATIONAL AVERAGE ELECTRIC UTILITY FUEL MIX

INDUSTRY/ ELECTROTECHNOLOGY	ESTIMATED CO_2 REDUCTIONS/UNIT	PERCENT CO_2 REDUCTION/UNIT	PROJECTED INDUSTRY-WIDE ANNUAL REDUCTION (Year Total Market Potential Realized)
Metals:			
Electric Arc Furnace	2,626 lbs/ton steel	75%	2.10 x 10^{10} lbs (2000)
Induction Heating			
- Billet Forging	352 lbs/ton billets	35%	Unknown
- Steel Hardening	22,818 lbs/ton steel	44%	Unknown
Induction Melting	None	None	None
Plasma-Fired Cupola	None	None	None
Infrared Heating			
- Steel Coating	2.3 lbs/1000 ft of steel coated	46%	Unknown
- Coating/Curing Lighting Poles	23.5 lbs/pole manufactured	57%	Unknown
Glass:			
Electric Melting	64 lbs/ton glass	8%	Unknown
Electric Forehearth	40 lbs/ton glass	67%	Unknown
Electric Lehr	40 lbs/ton glass	67%	Unknown
Food/Paper/Chemical:			
Freeze Concentration			
- Milk and Whey	Unknown	Unknown	5.5 x 10^{8} lbs (2015)
- Black Liquor	Unknown	Unknown	2.9 x 10^{10} lbs (2022)
- Caustic Soda	Unknown	Unknown	6.6 x 10^{9} lbs (2000)
- Alcohol Refining	Unknown	Unknown	8.3 x 10^{8} lbs (2015)
- BTX	Unknown	Unknown	2.7 x 10^{9} lbs (2015)
- Other potential applications (see Table 3-7)	Unknown	Unknown	2.0 x 10^{11} lbs (2015) (rough estimate)

TABLE E-2
CARBON DIOXIDE REDUCTION FROM VARIOUS MODES OF ELECTRIFIED TRANSPORTATION

TRANSPORTATION MODE	BTU PER MEASURE REQUIREMENT	CO2 PRODUCED PER UNIT (lbs)	PERCENT CO2 SAVINGS	1988 TOTAL U.S. ENERGY REQUIREMENTS FOR TRANSPORT TYPE (Btus)	1988 TOTAL SECTOR CO2 PRODUCED (lbs)	TOTAL CO2 SAVINGS (lbs per year)
Passenger Vehicles						
- Automobile	6524/vehicle mile	1.141		1.05×10^{16}	1.84×10^{12}	5.3×10^{10}
- Electric Vehicle	2764/vehicle mile	1.118	2.09			
Trains (Passenger & Freight)						
- Diesel	3.23 (1/efficiency)	5.64×10^{-4}		6.56×10^{14} (net of current electric use)	1.15×10^{11}	
- Electric	1.18 (1/efficiency)	4.80×10^{-4}	14.89			1.7×10^{10}
Buses						
- Gasoline Bus	1138/passenger mile	0.199		1.05×10^{12} *	1.84×10^{8}	
- Trackless Trolley	137/passenger mile	0.056	71.86			1.3×10^{8}
- Diesel Bus	771/passenger mile	0.135		4.59×10^{13} *	8.03×10^{9}	
- Trackless Trolley	137/passenger mile	0.056	58.52			4.7×10^{9}
Trucks **						
- Large Semi-Trailer Truck	1110/ton mile	0.194		1.34×10^{15} (32% of all truck Btus)	2.34×10^{11}	
- Electric Train	255/ton mile	0.104	46.39			1.1×10^{11}
Total						1.9×10^{11}

References:

- Electric Power Research Institute, Opportunity and Risk Assessment: Electric and Hybrid Vehicles - Strategic Issues for the 1980s (EPRI EM-2068), Prepared by Purdue University, West Lafayette, ID (October 1981).
- Energy Information Administration, Monthly Energy Review (DOE/EIA-0035[88/08]) Washington, DC (August 1988).
- Shonka, D.B. et. al., Transportation Energy Conservation Data Book, Ed. 2, Oak Ridge National Laboratories (ORNL-5320)

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* Intra-city only.

** Cross substitution analysis.

1.0 INTRODUCTION

Concerns relative to recent global warming trends observed by members of the scientific community have increased pressure to amend the Clean Air Act and to introduce more restrictive legislation on carbon dioxide (CO_2) emissions, as well as other "greenhouse gases." Traditionally thought of as a non-polluting by-product of fossil fuel combustion and several natural processes, CO_2 is now considered one of the major contributors to potential global warming and the greenhouse effect. Other gases such as chlorofluorocarbons, nitrogen oxides, and methane are also large contributors.

The U.S. Department of Energy (DOE) estimates that 35 percent of man-made CO_2 in the United States is emitted from the electric utility sector, 32 percent from transportation sources, 20 percent from industry, and the remaining 12 percent from combined other sources.[1] Because the utility industry is the most visible and possibly the largest contributor, legislative efforts often focus on this sector. The utility industry, however, has a positive story to tell relative to the advantages of using efficient electrotechnologies to replace or conserve fossil fuel use and to reduce CO_2 production in the transportation and industrial sectors. There may also be advantages in the residential sector but they are not covered here.

Industrial electrotechnologies and electric transport are often several times more energy efficient than their fossil fuel counterparts. They typically require less energy to perform the same amount of work, which has the potential to significantly reduce CO_2 levels in several applications.

The level of CO_2 reduction is dependent upon the level of efficiency of the electrotechnology and the electric utility industry's fuel mix for generating the electricity. For example, the greater the use of non-CO_2 producing fuels, such as nuclear and hydro, the less CO_2 produced from the use of the electrotechnology.

The movement toward electric substitution in many industrial and transportation applications could provide significant benefits in addition to reducing CO_2 levels. Several established electrotechnologies offer significant efficiency and productivity benefits that help to substantially improve industry's competitiveness in the United States. In addition, electric transport could further reduce other damaging air pollutants such as nitrous oxides and ozone, particularly in the urban environment.

The goal of this study was to provide a broad "macro-view" of the potential for CO_2 change from the increased use of electricity in industrial and transportation applications.

A methodology was developed to begin to identify those electrotechnologies that significantly reduce CO_2 in order to help guide future utility, industrial, transportation, research, and legislative efforts.

The methodology consists of a multi-step process, a simplified example of which is included in Table 1-1. For comparable fossil fuel and electric end-uses, the methodology includes:

- identifying end-use energy requirements for each process or transport type;
- calculating the amount of CO_2 generated per process based on the amount of energy consumed by using established algorithms for the amount of CO_2 produced per fuel type;
- calculating the CO_2 difference between the electric and fossil-fueled process or transport type;
- estimating market penetrations of the electrotechnology or electric transport type if CO_2 reductions would result from substituting electrotechnologies; and
- calculating total CO_2 reductions on an industry-wide basis.

Figure 1-1 illustrates the tasks taken to complete this effort.

This effort was designed to provide a preliminary scoping of the concepts, methodologies, and feasibility of reducing CO_2 levels through increased electrification in the transportation and industrial sectors. Carbon dioxide reduction is a complex issue and significant research in all sectors is required to assess and quantify potential reductions on both a national and state basis.

The following sections provide an overview of the research conducted and the preliminary results.

References:

1. "Technical Feasibility and Implications of Reducing U.S. CO_2 Emissions in the Period from 1995 to 2010," a briefing to Al Streeb, Deputy Assistant Secretary for Energy Conservation (March 4, 1988).

TABLE 1-1

SIMPLIFIED METHODOLOGY FOR QUANTIFICATION OF CO_2 REDUCTION FROM INCREASED ELECTRIFICATION

EXAMPLE: Manufacturing Process

---

1. Determine the amount of CO_2 produced per unit of product using a fossil fuel such as gas:

$$\frac{\text{amount of natural gas}}{\text{year}} \times \frac{(\text{ft3})}{(\text{year})} \times \begin{matrix}\text{process}\\ \text{efficiency}\\ \text{factor}\end{matrix} \times \frac{\text{amount of } CO_2 \text{ (lbs)}}{\text{amount of gas (ft3)}} \div$$

$$\frac{\text{amount of product (ton)}}{\text{year}} = \frac{\text{amount of } CO_2 \text{ produced (lbs)}}{\text{ton of product (ton)}} = \text{NG } \frac{CO_2}{\text{ton}}$$

---

2. Determine the amount of CO_2 produced from substitution of electrotechnology:

$$\frac{\text{amount of electricity required (kWh)}}{\text{ton of product (ton)}} \times \frac{\text{amount of } CO_2}{\text{kWh}} = \text{ELECT } \frac{CO_2}{\text{ton}}$$

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3. Estimate of CO_2 reduction by electrotechnolgy substitution:

$$\text{NG } \frac{CO_2}{\text{ton}} - \text{ELECT } \frac{CO_2}{\text{ton}} = \text{Y } \frac{CO_2 \text{ saved}}{\text{ton}}$$

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4. Estimate potential market penetration of electrotechnology (use available data and models if applicable).

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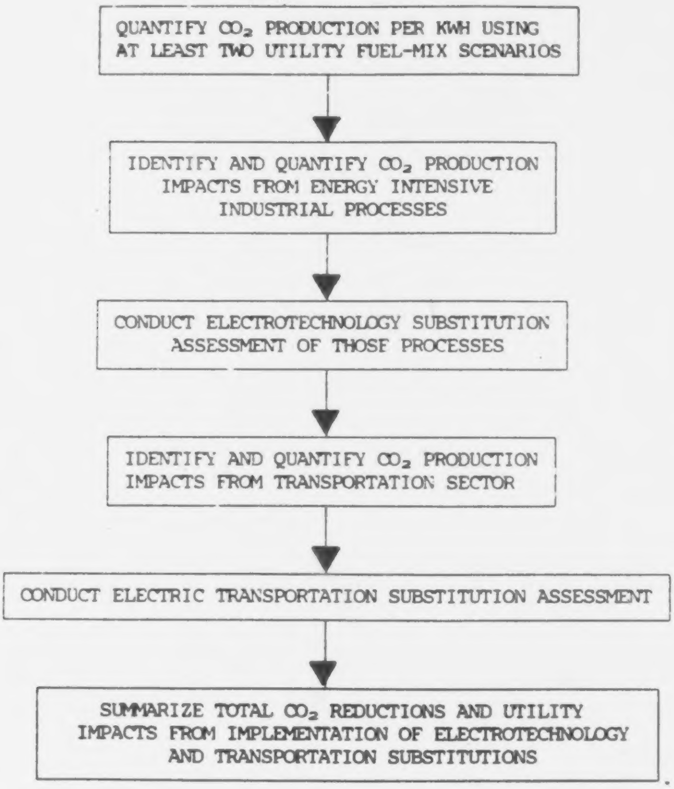
5. Estimate total CO_2 savings using electrotechnology market penetration results:

$$\text{Y } \frac{CO_2}{\text{ton}} \times \begin{matrix}\text{market}\\ \text{penetration}\\ \text{factor}\end{matrix} \times \begin{matrix}\text{base}\\ \text{quantity of}\\ \text{product}\end{matrix} = \text{Z } CO_2 \text{ savings}$$

FIGURE 1-1

TASKS CONDUCTED TO COMPLETE A MACRO STUDY OF CARBON DIOXIDE REDUCTION THROUGH ELECTRIFICATION


QUANTIFY CO_2 PRODUCTION PER KWH USING AT LEAST TWO UTILITY FUEL-MIX SCENARIOS
IDENTIFY AND QUANTIFY CO_2 PRODUCTION IMPACTS FROM ENERGY INTENSIVE INDUSTRIAL PROCESSES
CONDUCT ELECTROTECHNOLOGY SUBSTITUTION ASSESSMENT OF THOSE PROCESSES
IDENTIFY AND QUANTIFY CO_2 PRODUCTION IMPACTS FROM TRANSPORTATION SECTOR
CONDUCT ELECTRIC TRANSPORTATION SUBSTITUTION ASSESSMENT
SUMMARIZE TOTAL CO_2 REDUCTIONS AND UTILITY IMPACTS FROM IMPLEMENTATION OF ELECTROTECHNOLOGY AND TRANSPORTATION SUBSTITUTIONS

2.0 ELECTRIC UTILITY ANALYSIS: DEVELOPING A BASIS FOR COMPARISON

Electrification provides significant opportunities for CO_2 reduction. Because of the large size of central generating stations, utility power plant emissions can be more easily regulated than the myriad of residential, commercial, industrial, or transportation fossil fuel end-uses. In addition, further CO_2 production control exists from the opportunity to optimize future utility fuel mixes.

In order to compare CO_2 production from comparable electric and fossil fuel end-use technologies in the industrial and transportation sectors, an overall evaluation of CO_2 production in the electric utility sector was conducted. This task consisted of determining current and future average levels of CO_2 production, which included calculating the amount of CO_2 produced during the combustion of fossil fuels to generate electricity.

CO_2 generated during the fuel extraction processes for coal, natural gas, and petroleum refining were not included in any of the sector analyses. Our focus was strictly on the end-user's fuel choices and combustion products. In fact, primary energy used in mining extraction, transportation, etc., should not substantially influence the overall outcome of this analysis since it applies to energy used in utilities as well as energy used in transport or industry. While this aspect is important for a highly precise CO_2 estimate, it was not included here, as our purpose was to identify CO_2 reducing trends of electrification.

When focusing on the CO_2 reduction benefits of electrotechnologies, one might logically ask what type of fuel will be used to provide the additional electric generation required. The answer to this question of marginal, or next source of electrical production, has two components. The short term answer is that natural gas and oil predominate throughout the country as the marginal units, the net effect of which is to reduce the average amount of CO_2 per kWh delivered.

In the longer term, the 1997 mix (which incorporates the next units of planned addition to the U.S. utility generation mix) is expected to produce slightly less (1.39 --> 1.38) CO_2 per kWh than today's mix. Therefore, when both marginal factors are taken into consideration, their tendency is to reduce the overall amount of CO_2 created by virtue of new electrification. Therefore, our estimate of the CO_2 reducing benefits from the use of certain electrotechnologies may be somewhat conservative.

Our focus was to assess the national perspective to make our study potentially useful for national policy and decision makers. Therefore, we tried to be conservative in our assumptions and to emphasize what is known today without adding significant projections relative to the natural dispatch order or future additional units. These issues impact on particular regional variations. They involve current generation resources (whose mixes differ significantly across the nation) as well as future options with their associated regulatory, resource, economic, and political constraints. We therefore calculated "pounds of CO_2 produced" on a national average kWh basis.

2.1. Current Electric Utility Carbon Dioxide Production

In 1988, CO_2 emissions from the electric utility sector totalled 2.5 trillion pounds, resulting from the use of fossil fuels such as coal, natural gas, and oil. In comparison, the industrial sector emitted 1.5 trillion pounds, and the transportation sector, 2.3 trillion pounds.[1]

On a heat delivered or BTU (British Thermal Unit - the heat required to raise 1 pound of water one degree Fahrenheit) basis, coal is the largest fossil fuel CO_2 emitter, followed by oil and natural gas. Other utility generation fuels such as hydroelectric and nuclear produce no CO_2. The following table provides an estimate of CO_2 production from the combustion of various fuels. These estimates were derived by conducting stoichiometric assessments of combustion for each fuel type.[2]

CO_2 PRODUCTION BY FUEL TYPE

Fuel	Lbs CO_2/Quantity	Lbs CO_2/BTU
Coal	2.3 lbs/lb coal	1.9×10^{-4}
Oil	25 lbs/gallon	1.7×10^{-4}
Natural Gas	11.9×10^{-2} lbs/ft^3	1.2×10^{-4}

To put these numbers in perspective, the following are average annual CO_2 emissions from a 1,000 megawatt generating plant:

- Coal - 8.76 billion lbs.
- Oil - 8.28 billion lbs.
- Natural Gas - 5.68 billion lbs.
- Hydroelectric - 0 lbs.
- Nuclear - 0 lbs.

The total amount of CO_2 produced by the utility sector in 1988 was calculated by quantifying the amount of fuel consumed for electric generation in kWh. Using the values derived for estimating CO_2 production from the combustion of each fuel type, the total amount of CO_2 produced was calculated, and an average "lbs. CO_2/kWh" was derived.

On a national average basis in 1988, it was calculated that 1.39 pounds of CO_2 are emitted for every kWh generated. Table 2-1 displays these results. As the results indicate, the utility fuel mix in the United States is heavily dominated by coal use, the largest CO_2 emitter in the fuel mix. Assessment of pounds of CO_2 generated per kWh on a regional or state basis would provide a different insight into CO_2 production rates, which vary significantly with fuel mix differences that exist across the nation.

A second variable of interest is that non-CO_2 producing fuels can be used to generate electricity. This is not true of any other currently available resource for end-use energy consumption. Therefore, electricity has some additional unique properties and advantages that may provide assistance in the effort to reduce CO_2, one of the major component of the "greenhouse" gases.

2.2. Future Electric Utility CO_2 Production

Using the same methodology for calculating current electric utility CO_2 production, future CO_2 production levels were estimated. Table 2-2 contains the forecasted 1997 fuel mix and associated CO_2 production. The 1997 mix forecasted by the North American Electric Reliability Council (NERC) will produce about .75 percent less CO_2 per kWh than the current mix. This comes predominantly from a slight reduction in coal use coupled with a slight increase in nuclear, hydroelectric, and natural gas use. The category of "other" sources of generation increases rather significantly during the period and consists of primarily fossil-fired non-utility generation (small and independent power producers and cogenerators).

Since the "other" sources were presumed in this analysis to have the CO_2 output of coal, further research into the precise mix of these sources would most likely result in lower CO_2 emissions. "Other" is estimated to include a mix of refuse-to-energy plants, geothermal, wind, cogeneration, and traditional generation. Further research into identifying these sources and their fuels would most likely result in a lower CO_2 emission estimate on both a national and a state basis.

TABLE 2-1
1988 ELECTRIC UTILITY CARBON DIOXIDE PRODUCTION

FUEL	1988 NET [a] GENERATION (billion kWh)	PERCENT OF FUEL MIX	UTILITY BTU INPUT (quadrillion Btu)	QUANTITY OF CO_2 PRODUCING FUEL CONSUMED	CO_2 PRODUCED (trillion lbs)
Coal [b]	1,034.0	56.6	10.7	8.97×10^{11} lbs [c]	2.07
Natural Gas	185.7	10.1	1.99	1.99×10^{12} cubic ft.	0.24
Oil	92.2	5.0	0.97	1.62×10^{8} barrels	0.17
Nuclear	354.4	19.4	3.82	-----	--
Hydro	153.4	8.4	1.78	-----	--
Other [c]	8.0	0.4	0.15	2.37×10^{10} lbs "other"	0.06
Total	1,827.7				2.54

Total CO_2 Produced: 2.54×10^{12} lbs
1.39 lbs CO_2/kWh

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[a] kWh generated is based on the 8 months growth for 1988 applied to the 1987 total, since the 1988 data is not yet available. Energy Information Administration, Monthly Energy Review, U.S. Department of Energy (August 1988).

[b] For this analysis, the reference coal source is 12,000 Btu/lb Illinois coal. Actual coal burned at utilities has a lower Btu content. CO_2 is proportional to Btu content, therefore, while actual lbs of coal burned at utilities is higher than the example, the CO_2 output is the same.

[c] "Other" includes wood, refuse, wind, geothermal and solar, of which 60% was assumed to be CO_2 producing with the CO_2 output equivalent of coal.

TABLE 2-2
1997 ESTIMATED ELECTRIC UTILITY CARBON DIOXIDE PRODUCTION

FUEL	ESTIMATED NET GENERATION [a] (billion kWh)	PERCENT OF FUEL MIX	UTILITY BTU INPUT (quadrillion Btu)	QUANTITY OF CO_2 PRODUCING FUEL CONSUMED	CO_2 PRODUCED (trillion lbs)
Coal [b]	1,624.7	55.2	16.9	1.4 x 10^{12} lbs	3.22
Natural Gas	257.7	8.7	2.8	2.8 x 10^{12} CF	0.33
Oil	120.7	4.1	1.3	2.2 x 10^{8} barrels	0.23
Nuclear	649.5	22.1	7.0	-------	--
Hydro	249.9	8.5	2.9	-------	--
Other [c]	39.9	1.4	0.79	1.2 x 10^{11} lbs "other"	0.28
Total	2,941.8				4.06

Total CO_2 produced: 4.06 x 10^{12} lbs.
1.38 lbs CO_2/kWh

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[a] North American Electric Reliability Council, 1988 Forecast.
Energy Information Adminstration, Monthly Energy Review, August 1988.

[b] For this analysis, the reference coal source is 12,000 Btu/lb Illinois coal. Actual coal burned at utilities has a lower Btu content. CO_2 is proportional to Btu content, therefore, while actual lbs of coal burned at utilities is higher than the example, the CO_2 output is the same.

[c] "Other" includes wood, refuse, wind, geothermal and solar, of which 60% was assumed to be CO2 producing with the CO_2 output equivalent of coal.

The apparent finding of more CO_2 per BTU for electricity deserves clarification. Many electric end-uses use considerably less energy than the comparable fossil-fueled process. Therefore, if an electric process has a significantly higher efficiency, it will use less energy and produce less CO_2 per BTU for the same process or end-use. This is the crux of the analysis.

One way of sorting through technology choices for reducing CO_2 is to look at the ratio of electric CO_2 per BTU over the comparative fossil fuel CO_2 per BTU. As shown below, reductions in CO_2 will occur through electrotechnology substitution only when the ratio of electric work per unit of energy is higher than the fossil fuel work per unit of energy by a specific amount. In other words, the table shows how much more efficient an electric technology must be compared to a fossil-fueled counterpart in order to reduce CO_2.

CO_2 per BTU Ratios Using 1988 National Average
Electricity Fuel Mix Scenario

Conversion From/To	Electric Efficiency Required Minimum for CO_2 Reduction
Gas/Electric	3.42
Oil/Electric	2.41
Coal/Electric	2.15

It is important to note that these ratios are based on the current national average electric utility fuel mix. Thus, significantly different ratios would be derived for each individual region, or each utility's service territory that differed from the average. These ratios were only derived to provide a comparative basis for this analysis.

Using these ratios, it was determined that an electrotechnology must be over 3.42 times more efficient than a natural gas-fired substitute, 2.41 times more efficient than an oil-fired technology, and 2.15 times more efficient than a coal-fired process in order to produce savings in CO_2 emissions. For each application, only end-use energy requirements were evaluated. Primary energy requirements using fossil fuels are similar whether the fossil fuel is burned in a power plant, industrial plant, or in the transportation sector. Therefore, the inclusion of primary energy used for fossil fuel production should not substantially alter the analysis. CO_2 produced from electric generation conversion is incorporated into the average "lbs. per kWh" value calculated in Section 2.1.

TABLE 2-3

ELECTRICAL ENERGY PRODUCTION BY FUEL
(Percent Total)

TABLE 17--ELECTRICAL ENERGY PRODUCTION BY FUEL (% TOTAL)

	1988						1997					
	Nuclear	Coal	Hydro[a]	Oil/Gas	Other (Utility)	NUGs	Nuclear	Coal	Hydro[a]	Oil/Gas	Other (Utility)	NUGs
ECAR	8.7	89.8	0.7	0.5	0.0	0.3	9.3	86.6	0.6	0.5	0.0	3.0
ERCOT	2.9	40.8	0.2	45.6	0.0	10.5	11.4	44.0	0.2	33.3	0.2	10.9
MAAC	31.2	52.6	2.1	11.7	0.6	1.8	32.4	44.6	1.6	9.7	0.4	11.3
MAIN	44.3	54.0	1.1	0.3	0.3	>0.0	42.3	54.7	1.0	1.7	0.3	0.0
MAPP-U.S.	19.9	68.6	10.5	0.6	0.3	0.1	17.8	70.8	9.8	1.0	0.3	0.3
NPCC-U.S.	27.7	19.0	13.7	36.5	0.0	3.1	31.2	17.1	11.4	27.6	0.0	12.7
SERC	27.3	59.8	5.8	5.8	>0.0	1.3	28.4	54.6	4.9	8.8	0.0	3.3
SPP	15.9	54.1	2.5	25.9	0.6	1.0	14.9	54.0	2.3	26.2	0.8	1.8
WSCC-U.S.	14.6	34.5	33.0	9.7	5.4	2.8	12.3	34.5	28.0	11.0	9.7	4.5
NERC-U.S.	20.2	54.3	9.5	12.8	1.1	2.1	20.8	52.1	8.0	12.2	1.9	5.0
MAPP-Can.	0.0	26.2	73.1	0.7	0.0	0.0	0.0	26.2	73.4	0.4	0.0	0.0
NPCC-Can.	28.9	11.9	57.7	1.4	0.0	0.1	30.9	12.3	54.0	2.3	0.0	0.5
WSCC-Can.	0.0	36.5	59.1	4.4	0.0	0.0	0.0	41.5	46.3	7.6	4.6	0.0
NERC-Can.	20.3	18.3	59.3	2.0	0.0	0.1	21.9	19.5	54.0	3.2	1.0	0.4
NERC-Mex.[b]	0.0	0.0	0.0	20.2	79.8[c]	0.0	0.0	0.0	0.0	39.7	60.3[c]	0.0
NERC-Total	20.2	49.6	15.9	11.4	1.1	1.8	20.9	47.5	14.5	10.9	1.9	4.3

[a] Conventional hydro. Adverse hydro except for a few systems with median or average hydro.

[b] Northern portion of Baja California, Mexico only.

[c] Geothermal electrical energy production.

Reference:

1988 Electricity Supply and Demand for 1988 - 1997, North American Electric Reliability Council.

In addition, in regions where off-peak electricity is generated by nuclear or hydro units, efforts to shift consumption to off-peak periods or to develop end-use technologies that can either store or use this off-peak electricity would result in further CO_2 reductions.

It is important to evaluate current and future fuel mix scenarios on a regional or state basis to obtain a more specific and accurate picture of CO_2 production. As can be seen in Table 2-3, the fuel mixes of the various NERC regions vary considerably. For example, three of the nine NERC regions tend to have non-CO_2 producing fuels as the marginal off-peak unit. By 1997, the number will increase to four regions with five of the nine regions reducing their coal use and increasing their nuclear use. This underscores the importance of evaluating utility CO_2 production on a regional or state basis, since these trends impact the CO_2 reduction potential of various electrotechnologies.

For simplicity, and because of the preliminary scoping nature of this effort, the average national CO_2 production rate was used to compare the use of electricity with industrial and transportation fossil fuel end-uses. Future research should account for regional or state differences in fuels used.

2.3. Developing an End-Use Method for Comparison

With many different ways of measuring energy, it is important to evaluate alternatives on a comparable basis. Since the BTU is a standard quantity of energy, it is convenient to convert energy consumption to BTUs to make comparisons. An initial screening process for substitution opportunities based on the number of BTUs consumed identified whether CO_2 savings would result. The following table shows the CO_2 produced per BTU at the end-use level for several energy sources. The estimated pounds of CO_2 per kWh of electricity is based on the current national average fuel mix. It is important to note that electricity appears more CO_2 intensive than the others. Electricity as a refined fuel has power plant conversion and losses taken into account to provide a fair comparison with other end-use energy sources.

CO_2 GENERATED PER END-USE BTU FOR VARIOUS FUEL TYPES

Electricity - 4.1 x 10^{-4} lbs CO_2/BTU
Coal - 1.9 x 10^{-4} lbs CO_2/BTU
Oil - 1.7 x 10^{-4} lbs CO_2/BTU
Natural Gas - 1.2 x 10^{-4} lbs CO_2/BTU

The following sections apply these concepts and findings to an evaluation of electrotechnologies in the industrial and transportation sectors.

References:

1. "Technical Feasibility and Implications of Reducing U.S. CO_2 Emissions in the Period 1995-2010," a briefing to Al Streeb, Deputy Assistant Secretary for Energy Conservation, March 4, 1988, Department of Energy, and 1988 estimates of utility CO_2 production by Energy Research Group, Inc.

2. "Environmental Impacts of Closing Yankee Rowe and Pilgrim Station," Energy Research Group, Inc., July 1988.

3.0 THE INDUSTRIAL SECTOR:
ELECTROTECHNOLOGIES THAT CAN REDUCE CARBON DIOXIDE LEVELS

The goal of the industrial sector analysis was to identify electrotechnologies that could be used to replace industrial fossil fuel processes and significantly reduce CO_2. To accomplish this goal, several analytical steps were taken.

First, a review of overall industrial energy use was performed. Second, a review of individual manufacturing processes in selected industries was conducted in parallel with an evaluation of electrotechnology substitution possibilities. Thereafter, analyses were performed on the electrotechnologies determined to be potential candidates for CO_2 reduction. Each step is discussed below.

3.1. Industrial Energy Use Overview

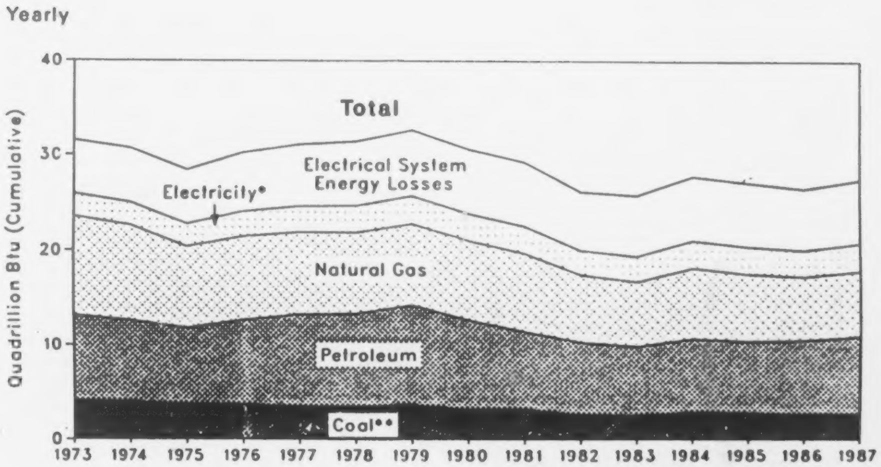
The industrial sector uses energy for a wider variety of purposes than any other sector. Natural gas is used because it burns cleanly and provides easy flame control and is used as a feedstock and fuel for a number of processes. Petroleum is used for direct heat applications and steam generation, and coal is used mainly for steam production, as there are relatively few products that can tolerate the impurities emitted by the direct burning of coal. Electricity has historically been used primarily for space heating, lighting, and mechanical drive applications.

Figure 3-1 illustrates energy consumption trends of the industrial sector since the early 1970s. Currently, the industrial sector consumes approximately 27 quadrillion BTU of energy annually.[1] About 86 percent is provided by the use of fossil fuels. In 1987, the industrial sector consumed about 0.223 trillion pounds of coal, 6.87 trillion cubic feet of natural gas, and 1.05 billion barrels of oil to meet energy requirements.[2] Within this sector, manufacturing accounts for about 75 percent of this energy use, mining for about 12 percent, and agricultural/construction another 6 percent.[3]

Applications that have the potential to substitute electric energy for industrial fossil-fuel based processes have been extensively researched and developed by both the electric utility and manufacturing industries for several reasons. For example, in some industrial uses, fossil fuels may be less efficient than

FIGURE 3-1

CONSUMPTION OF ENERGY BY THE INDUSTRIAL SECTOR



Reference:

Energy Information Administration, Monthly Energy Review, DOE/EIA-0035 (88/08), Washington, DC (August 1988).

electricity-based processes by a factor of three or more. Electrotechnologies allow precise control and focus of energy only when and where needed, even on a "primary energy" basis, which accounts for the efficiency losses in power generation and transmission.[4]

Electrotechnologies can also reduce costs for plant pollution control, reduce production floor space (because they are typically more compact than fossil fuel-fired ovens or furnaces), and can significantly reduce processing and production time.[5] These reasons more than counterbalance the 3-5 times fuel price advantage currently enjoyed by fossil fuels.

Electrotechnology substitution possibilities for this effort were focused on those manufacturing industries that consume the largest amount of energy, where it has been determined that electrification potential is the greatest. These include the following standard industrial classification categories:

- the primary metals industry (SIC 33);
- the stone/clay/glass industry (SIC 32);
- the chemicals industry (SIC 28);
- the petroleum refining industry (SIC 29);
- the pulp and paper industry (SIC 26); and
- the food industry (SIC 20).

Combined, these industries consume over 9 trillion BTUs of energy annually, most of which is derived from fossil fuels (see Table 3-1).

Since it has been estimated that approximately 75 percent of energy consumed in the industrial manufacturing sector is used for direct heat applications and steam production, electric substitutions in these areas were targeted.[6]

3.2. Electrotechnology Evaluation Criteria

Past and current research conducted by the Electric Power Research Institute (EPRI) in conjunction with research organizations such as the Centers for Metals Fabrication and Production and others, was used as the basis for selecting electrotechnologies that could potentially reduce CO_2 levels in the industrial sector. Table 3-2 contains the technologies that were included in the initial screening process.

A search of published literature and statistical data was performed on the listed technologies and targeted industries. In some cases, published data did not exist in the form required for

TABLE 3-1
ENERGY CONSUMPTION OF TARGETED INDUSTRIES
(1985) (Trillion Btu)

INDUSTRY (SIC)	NATURAL GAS	STILL GAS/ LPG	OIL PRODUCTS	COAL & COKE	PURCHASED STEAM	ELECT- RICITY	OTHER*	TOTAL
1. Petroleum (29)**	589	1,123	134	444	25	72	-	2,387
2. Paper (26)	306	3	158	335	18	143	1,201	2,164
3. Chemicals (28)	973	-	441	302	80	264	-	2,060
4. Iron/Steel (33)	348	-	35	974	-	150	412	1,001***
5. Stone/Glass/Clay (32)	397	-	33	343	-	114	39	926
6. Food (20)	459	-	65	132	-	166	34	856
TOTAL	3,072	1,126	866	2,530	123	909	1,686	9,394

* Includes internally generated fuels.
** 1984 consumption data.
*** Excludes coke.

References:

Based on information from the following publications from the American Gas Association, Arlington, VA:
- Industrial Sector Energy Analysis: The Paper Industry (February 12, 1988).
- Industrial Sector Energy Analysis: The Stone, Clay, and Glass Industries (April 8, 1988).
- Industrial Sector Energy Analysis: Food and Kindred Products (SIC 20) (May 21, 1988).
- Industrial Sector Energy Analysis: Chemical and Allied Products (SIC 28) (July 27, 1988).
- Industrial Sector Energy Analysis: Petroleum Refining (September 28, 1988).
- Industrial Sector Energy Analysis: The Steel Industry (September 28, 1988).

TABLE 3-2

ELECTROTECHNOLOGIES INITIALLY SCREENED FOR CARBON DIOXIDE REDUCTION

PROCESS INDUSTRIES

Electrochemical Synthesis
Electrolytic Separation
Freeze Concentration
Industrial Process Heat Pumps
Membrane Processes

METALS PRODUCTION

Direct Arc Melting
Induction Melting
Ladle Refining
Plasma Processing
Vacuum Melting

MATERIALS FABRICATION

Electrofinishing
Electroforming
Electron Beam (EB) Processing
Induction Heating and Melting
Infrared (IR) Processing
Laser Processing
Microwave Heating and Drying
Radio-Frequency (RF) Heating and Drying
Resistance Heating and Melting
Ultraviolet (UV) Curing

Reference:

Electric Power Research Institute, Electrotechnology Reference Guide, Rev. 1 (EPRI EM-4527), Prepared by Resource Dynamics Corporation, Vienna, VA (August 1988).

this type of analysis. In other cases, interpretation was needed before the results could be used for further evaluation. Because of the preliminary scoping nature of this project, a general research effort was conducted using the available resources on hand. Thus, the results are not intended to be comprehensive.

Research efforts focused on targeting electrotechnologies used for direct and indirect heating applications with significantly greater production efficiencies than their fossil-fuel counterparts. This was the major criteria for electrotechnology selection, as efficient technologies require less energy and theoretically should result in decreased CO_2 production. Other factors such as data availability, future market penetration impact and commercial availability of the electrotechnologies were also considered.

Based on the preliminary research conducted, Table 3-3 was shortened to include the following electrotechnologies targeted as having CO_2 reducing characteristics.

- Metals Industry:
  - electric arc furnace
  - induction heating
  - induction melting
  - plasma-fired technology
  - infrared heating
- Stone/Clay/Glass Industry:
  - electric glass melting, conditioning, and annealing
- Food, Chemical, Petroleum and Paper Industries:
  - freeze concentration

Since there has been a significant increase in electric use in the industrial sector in the past few years, we suspect that some CO_2 reducing contribution has already occurred. Other electrotechnologies may have CO_2 reducing characteristics as well, however, for the limited scoping nature of this effort, the above technologies were targeted for initial review. The results are discussed below.

3.3. Electrotechnology Analyses

The data required for calculating CO_2 emissions for each electrotechnology were obtained from economic evaluations conducted to compare the use of electricity with natural gas or other fossil fuel for a given end-use. Using the amount of electricity and fossil energy required for a particular process, the amount of CO_2 was determined. Only end-use energy requirements were used in the evaluations; as in the case of

TABLE 3-3

ALTERNATIVE STEELMAKING TECHNOLOGY ROUTES
EVALUATED FOR CO_2 EMISSIONS

TECHNOLOGY ROUTE	FEED STOCK PREPARATION	REDUCTION OF ORE	REFINING OF STEEL	STEEL PROCESSING		
1	Coke Pellets Sinter	Blast Furnace	Basic Oxygen Furnace	Ingot Casting	Ingot Mills	Hot Rolling Mills
2	Coke Pellets Sinter	Blast Furnace	Basic Oxygen Furnace	Continuous Casting		Hot Rolling Mills
3	Pellets	Direct Reduced Iron (coal)	Electric Arc Furnace	Continuous Casting		Hot Rolling Mills
4	Pellets	Direct Reduced Iron (MIDREX)	Electric Arc Furnace	Continuous Casting		Hot Rolling Mills
5	—	Steel Scrap	Electric Arc Furnace	Continuous Casting		Hot Rolling Mills

Reference: Electric Power Research Institute, *Technoeconomic Assessment of Electric Steelmaking Through the Year 2000* (EPRI EM-5445), prepared by the Center for Metals Production, Pittsburgh, PA (October 1987).

electricity, CO_2 produced from generation is incorporated into the average "lbs. per kWh" calculated in Section 2.

It was found that significant CO_2 reductions result from the use of several electrotechnologies compared to their fossil-fueled counterparts. It was also found that some electrotechnologies do not reduce CO_2 levels. The major findings are summarized below.

METALS INDUSTRY

Electric Arc Furnace

The traditional method of manufacturing steel products is a complex multi-step process that includes seven specific steps that transform raw material into finished steel. These include: agglomeration, coking, ironmaking, steelmaking, primary finishing, secondary finishing and heat treating. (See Figure 3-2)

Three methods are currently being used in the United States for steelmaking: the open hearth process, the basic oxygen process, and the electric arc furnace process. Prior to 1960, almost all steel was manufactured through the open hearth process where iron was kept hot by gas burners as long as was needed to react the carbon in the metal with oxygen. Currently, only 3 percent of steel in the United States is made in this way.[8]

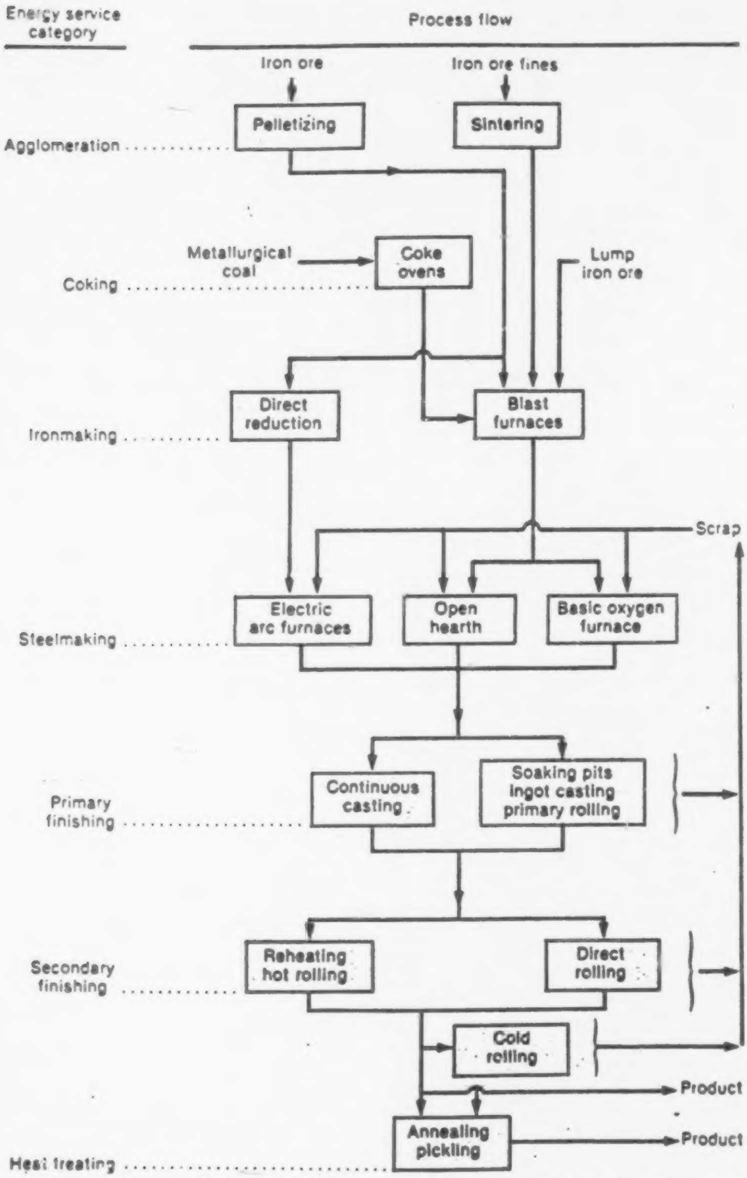
The basic oxygen furnace process blows almost pure oxygen onto the surface of the molten iron, which speeds the conversion to steel ten times faster than by open hearth conversion. This process is now displacing the older, less-productive furnace. Approximately 60 percent of steel produced in the United States in 1987 was made by using this process.[8]

An alternative to the traditional integrated steel making process involves use of the electric arc furnace, which produces molten steel from scrap metal. The electric arc furnace eliminates the agglomeration, coking and ironmaking steps that must be executed in integrated steel operations, which typically use only about 30 percent scrap metal. (See Figure 3-3.)

An electric arc furnace is a cylindrical refractory vessel comprised of a shell which holds the charge, water cooled wall and roof panels, and electrode holding and automatic positioning mechanisms that maintain the proper arc length.

FIGURE 3-2

PROCESS FLOWS IN THE IRON AND STEEL INDUSTRY


Energy service category
Process flow
Iron ore
Iron ore fines
Pelletizing
Sintering
Agglomeration
Metallurgical coal
Coke ovens
Lump iron ore
Coking
Direct reduction
Blast furnaces
Ironmaking
Scrap
Electric arc furnaces
Open hearth
Basic oxygen furnace
Steelmaking
Continuous casting
Soaking pits ingot casting primary rolling
Primary finishing
Reheating hot rolling
Direct rolling
Secondary finishing
Cold rolling
Product
Annealing pickling
Product
Heat treating

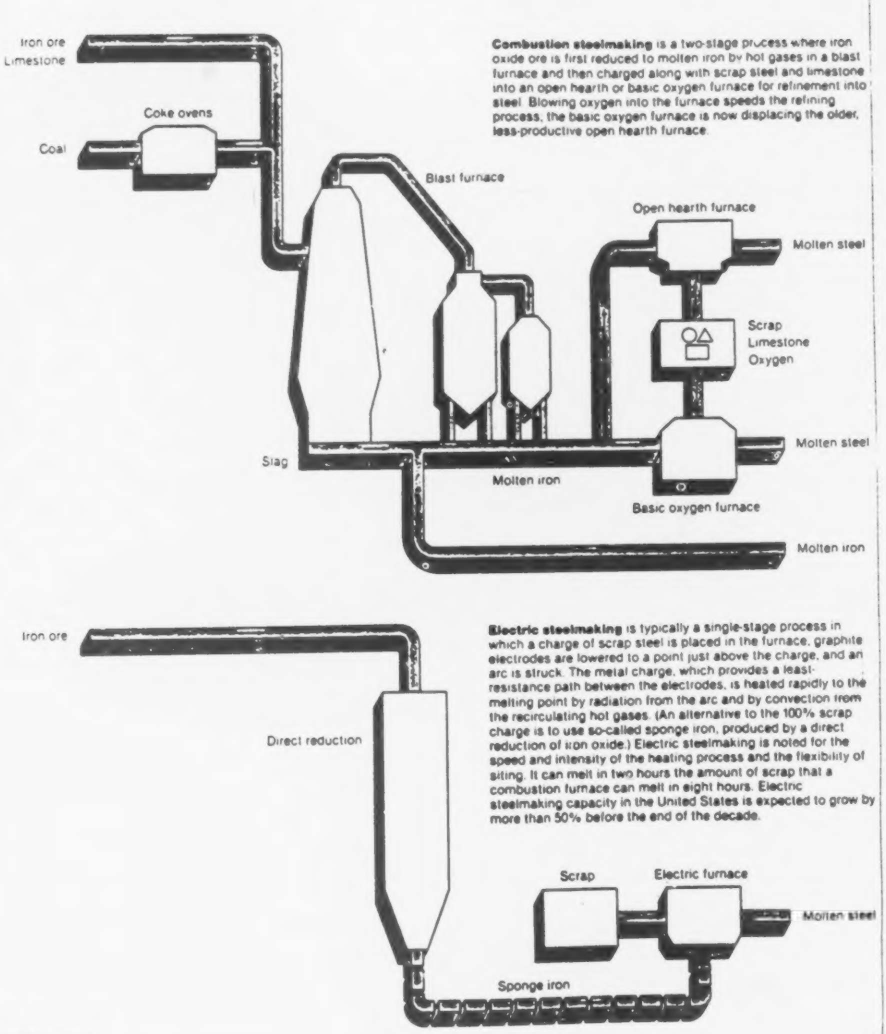
SOURCE: Energy Productivity Center, Mellon Institute, *Final Report on Industrial Energy Productivity Project, Volume 4, The Iron and Steel Industry*, September 1982

Reference:

Office of Technology Assessment, Industrial Energy Use, Washington, DC (June 1983).

FIGURE 3-3

COMPARISON OF COMBUSTION AND ELECTRIC STEELMAKING


Iron ore
Limestone
Coke ovens
Coal
Blast furnace
Open hearth furnace
Molten steel
Scrap
Limestone
Oxygen
Molten steel
Slag
Molten iron
Basic oxygen furnace
Molten iron
Iron ore
Direct reduction
Scrap
Electric furnace
Molten steel
Sponge iron

Combustion steelmaking is a two-stage process where iron oxide ore is first reduced to molten iron by hot gases in a blast furnace and then charged along with scrap steel and limestone into an open hearth or basic oxygen furnace for refinement into steel. Blowing oxygen into the furnace speeds the refining process; the basic oxygen furnace is now displacing the older, less-productive open hearth furnace.

Electric steelmaking is typically a single-stage process in which a charge of scrap steel is placed in the furnace, graphite electrodes are lowered to a point just above the charge, and an arc is struck. The metal charge, which provides a least-resistance path between the electrodes, is heated rapidly to the melting point by radiation from the arc and by convection from the recirculating hot gases. (An alternative to the 100% scrap charge is to use so-called sponge iron, produced by a direct reduction of iron oxide.) Electric steelmaking is noted for the speed and intensity of the heating process and the flexibility of siting. It can melt in two hours the amount of scrap that a combustion furnace can melt in eight hours. Electric steelmaking capacity in the United States is expected to grow by more than 50% before the end of the decade.

Reference:

"Electrotechnology: Sparking Productivity in Industry," EPRI Journal (June 1982)

The electric arc furnace also employs a mechanism to remove the roof for charging, tapping, and deslagging.[10]

In electric arc furnace steelmaking, scrap is charged into an empty furnace, and the arc melts a hole down through the scrap using the scrap metal to shield the walls from the arc-flare. Once all the scrap is melted, the voltage is lowered to reduce the arc length and, consequently, the power in order to protect the walls and roof from excessive radiant heat.[11]

The total amount of energy required per ton of steel produced has been determined to be about 15 MBTU for both the open hearth and the basic oxygen furnace processes, compared to about 6.3 MBTU for steelmaking from the electric arc furnace using scrap metal (or 2.1 MBTU using electricity counted at its end-use value at 3,413 BTU/kWh).[12] The large difference in energy requirements stems from the fact that electric steel is made from scrap, thus energy is not required for cokemaking and blast furnace iron making.

Finished steel products can be manufactured by several combinations of unit operations involving basic oxygen and electric arc furnaces. Five popular combinations of these operations or "technology routes" were reviewed for CO_2 production and are included in Table 3-3. The technology routes range from the most integrated process to the least integrated, which utilizes the electric arc furnace to melt steel scrap.

The CO_2 levels for each technology route were estimated using the overall energy requirements per ton of steel manufactured for each process. Table 3-4 contains a list of the processes and energy requirements. As can be seen, electric arc steelmaking from scrap results in the lowest amount of CO_2 per ton of steel. If electric arc furnace steelmaking was substituted for the other technology routes, CO_2 reductions would range from 1,651 pounds of CO_2 per ton to 3,093 pounds of CO_2 per ton, the average being 2,626 pounds of CO_2 per ton.

There are several other advantages of steelmaking using the electric arc furnace. For example, the capital cost for building an electric arc furnace steelmaking plant is considerably less than for an integrated facility because there is no need for a pellet plant, coke plant, blast furnaces, hot metal treatment equipment, etc. In addition, scrap generally costs less and requires less labor, and there are fewer environmental considerations.[13]

TABLE 3-4

CARBON DIOXIDE EMISSIONS FROM
ALTERNATIVE STEELMAKING TECHNOLOGY ROUTES

	ENERGY REQUIREMENTS (per ton of steel)[a]				
TECHNOLOGY ROUTE	Electricity (kWh)	Natural Gas (kCF)	Oil (gal)	Coal[b] (lbs)	CO_2 Produced (lbs/ton)
1. BF/BOF/IC	403.52	0.26	6.05	1,400	3,963
2. BF/BOF/CC	339.65	0.23	5.40	1,[illegible]60	3,[illegible]32
3. EAF/DRI:COAL	1,043.96	--	3.27	1,0[illegible]8	3,966
4. EAF/DRI:MIDREX	924.85	9.61	--	40	2,521
5. EAF/SCRAP	625.56	--	--	--	870

a. Does not include requirements for steam (which range from 0 to 322.4 lbs/ton steel) or mixed fuels (which range from 1.62 to 2.55 MBTU/ton steel), as their compositions are uncertain. Since steam production does require the use of fossil fuel, the CO_2 produced per ton is underestimated. In addition, the estimates calculated do not take into consideration the possibility of using waste gases for cogeneration purposes.

b. most of the coal used in steelmaking is for producing coke. It was assumed that the same CO_2 factor used for coal combustion applies to coke production.

Reference:

Electric Power Research Institute, Technoeconomic Assessment of Electric Steelmaking Through the Year 2000 (EPRI EM-5445), Prepared by Center for Metals Production, Pittsburgh, PA (October 1987).

Disadvantages include no production of new iron, production of a dust in the off-gas which is classified as hazardous waste, and nitrogen levels in the steel that could make it difficult to produce certain grades of steel.

Currently in the United States, approximately 38 percent of steel, or 34 million tons, is produced from the use of electric arc furnaces using scrap metal. This figure is up from less than 10 percent about 20 years ago.[14] The future market penetration of electric arc furnace use will be partially dependent on the amount of scrap steel available.

EPRI projects that electric arc steelmaking could capture the equivalent of 42 million tons of raw steel production by the year 2000.[15] Conservatively assuming steel production rates will remain at the 1987 rate, an additional 8 million tons of raw steel could be produced using the electric arc furnace. Assuming an average CO_2 reduction of 2626 pounds per ton of steel, this could result in an annual CO_2 reduction of 21 billion pounds by the year 2000.

Induction Heating

Electromagnetic induction heating is a process used to heat metals to transform them into finished products. For example, induction heating can be used in such metal processes as hot working, heat treatment and welding. Heating results from a rapidly fluctuating magnetic field which induces electric currents in the metal.

In the last half century, induction heating has been found to be a reliable, acceptable heating technique. Induction heating systems have efficiencies ranging from 55 to 85 percent compared to natural gas-fired furnaces with efficiencies ranging between 20 and 25 percent.[16]

Two common induction heating applications were compared with heating methods using natural gas to determine CO_2 levels. These applications included induction heating to soften metal billets prior to forging (heating prior to working), and induction heating for surface hardening of steel. Each application is separately discussed below.

Forging is a thermomechanical process which shapes metal parts, or billets, by the application of controlled force. The billets are heated prior to forging, either in a fuel-fired or an electric induction furnace. Induction heating is widely used because of its speed and selected heating capabilities.

CO_2 emissions were calculated for the heating of several billet sizes using natural gas in a conventional furnace and for induction heating methods. It was found that the induction heating thermal efficiencies varied by billet dimension, and that in all cases, CO_2 reductions occurred using electric induction heating over natural gas. The results are included in Table 3-5. CO_2 reductions range from 13 to 41 percent, with the average being 35 percent.

Another common process using induction heating involves hardening the surface of mass-produced steel parts. Steel is hardened by controlling the cooling rate and temperature of the metal. Carbon dioxide emission levels were evaluated using electric induction heating and a natural gas-fired furnace. It was found that 72 MBTUs are needed per ton of steel using induction heat and 438 MBTUs using natural gas.[17] The total amount of CO_2 savings per ton of steel using induction heating was calculated to be approximately 22,818 pounds per ton, or a 44 percent reduction.

Market penetration information on the use of induction heating for these applications was not readily available. In addition, several other induction heating applications could produce similar CO_2 reductions. Thus, additional research is required to further estimate individual process and industry-wide CO_2 reductions.

Induction Melting

Induction melting is used primarily for refining and remelting metals. Induction melting equipment consists of either a coreless furnace, which involves the melting of metal in a crucible, or a furnace in which a small portion of the total charge is heated in a small channel and then recirculated in a main melting chamber.

Benefits of using induction melting equipment include:

- fast start-up, less time needed to reach working temperature;
- cleaner melting, no by-products of combustion;

TABLE 3-5
CARBON DIOXIDE EMISSIONS FROM INDUCTION VERSUS
GAS-FIRED HEATING OF FORGING BILLETS

BILLET SIZE (inches)	GAS-FIRED PROCESS		INDUCTION PROCESS		CO_2 REDUCTIION USING INDUCTION HEATING (lbs/ton)
	Thermal Requirements (mBtu/ton)	CO_2 Production (lbs/ton)	Thermal Requirements (MBtu/ton)	CO_2 Production (lbs/ton)	
4 x 18	8.42	1002	1.45	590	412
2 x 6	8.42	1002	1.47	598	404
2 x 60	8.42	1002	1.48	602	400
7 x 6	8.42	1002	2.14	871	131
4 x 8	8.42	1002	1.45	590	412

Reference:

Electric Power Research Institute, Electrical Heating of Forging Billets (EPRI EM-2644), Prepared by The University of Texas, Austin, TX (November 1982).

- automatic operation;
- compact installation; and
- energy conservation.[18]

Data were extracted from comparative evaluations of melting ferrous and nonferrous metals using cupola, oil-fired and induction furnaces to evaluate CO_2 production.[19] While it was found that the electric induction heating furnace requires approximately half the energy of fossil-fired processes, the increased efficiency was not large enough to produce CO_2 savings using the national average electricity generation fuel mix as a basis. In regions where significant quantities of non-CO_2 or lower CO_2 producing fuel sources, such as nuclear, hydro, or natural gas are used for electricity generation, CO_2 reductions could occur using this technology.

Plasma-Fired Cupola

The basic techniques of melting iron for foundry casting have remained the same for about 200 years. The vertical shaft coke-fired furnace known as the cupola has been used most frequently. Because of high operating costs and air pollution control costs, however, the use of the cupola is decreasing. Cupolas are being replaced by electric induction and electric arc furnaces. However, at foundries with high outputs and continuous demand, the cupola remains the lowest-cost melting method.[20]

As an alternative to the conventional coke-fired cupola, EPRI research developed a plasma-fired cupola, in which heat supplied by a plasma torch replaces much of the heat normally supplied by the combustion of fossil fuel. The plasma-fired cupola offers a reduction of up to 30 percent in the cost of producing hot metal through savings from the use of less expensive scrap metal charge materials and reduced energy costs.[21]

Based on sample calculations of a hypothetical case study conducted by EPRI, CO_2 emissions were calculated from a conventional cupola and a plasma-fired cupola.[22] It was found that while the plasma-fired cupola reduced natural gas consumption by about 34 percent, coke use by 29 percent, and ancillary electric power by 34 percent, the large amount of electricity required for the plasma torch and accessories does not produce CO_2 reductions using the national average generation fuel mix as a basis. However, CO_2 reductions may occur using this technology in areas of the country where large amounts of non- or lower- CO_2 producing fuels are used for electric generation.

Infrared Heating

Electric infrared (IR) heating was developed by the Ford Motor Company in the 1930s for curing finishes on automobile bodies. Use of the technology, however, was limited because of difficulties in controlling IR emitters and adapting them to specific applications.[23]

Today, technology improvements have expanded the use of IR heating for curing and drying applications in the metals processing, automotive, textile, paper, plastics, and other industries. IR occupies the part of the electromagnetic spectrum between visible light and radio waves. Medium-wave IR emitters are used where a lower temperature, more diffuse source of heat is required, such as for drying water from surfaces, or curing inks. Shortwave, or high-intensity, IR systems are used where intense, directed heat is required, such as in curing thick coatings.

Electric IR ovens are about four times as efficient as convection ovens. Short wave emitters are 85 to 90 percent efficient, compared with 60 to 65 percent for medium wave lamps. Generally, 50 to 70 percent of the radiant energy is absorbed by the product. In comparison, in gas IR ovens, only about 25 percent of the input energy reaches the product, and in gas convection ovens it is only 15 percent.[24] Other advantages include higher productivity, space savings, precise control, low maintenance, and clean products.

Two case studies using IR processing were examined to evaluate the amount of carbon dioxide produced. The first application involved the manufacture of coated steel. The company replaced 180 feet of gas-fired convection ovens with 17 feet of electric IR heating units, which decreased energy costs from $9.92 to $6.92 per hour.[25] Conservatively assuming that the cost of electricity was $0.06 per kwh and the cost of gas was $4.00 per MBTU, the energy requirements were calculated to be 0.39 MBTU of electricity required for IR heating and 2.48 MBTU of natural gas for convection heating. It was calculated that CO_2 production from the natural gas convection ovens totalled 295 pounds per hour compared to 159 pounds per hour from the use of electric IR heating. Thus, a CO_2 reduction of 136 pounds per hour can be realized from the use of IR heating in this particular application.

The second case study involved the replacement of an air-dried acrylic finish application used in the manufacture of light poles, with a powder coating cured with medium and short wave IR.[26] It was found that curing the powder coating with electric IR cost $0.86 per pole compared with $1.59 in a gas oven. Again assuming the cost of electricity was $0.06 per kwh and the cost of natural gas was $4.00/MBTU, the energy requirements for each process were calculated to be: 0.049 MBTU using electric IR curing and 0.39 MBTU using gas-fired convection curing. The CO_2 savings using electric IR were calculated to be 23.5 pounds of CO_2 per pole.

Detailed market penetration data were not available to determine total impact from large scale IR processing substitutions. These examples were provided to illustrate that CO_2 savings can result from the use of IR processing in place of convection ovens using fossil fuels.

GLASS INDUSTRY

The glass industry, a relatively large and well-established industry, is a large user of thermal energy. In 1985 alone, energy consumption totalled over 300 trillion BTU.[27]

Glass production is categorized into four industry groups: pressed and blown ware, containers, flat glass, and fibers. Glass containers are the dominant product, with a production rate of approximately 15 million tons annually. The total glass industry production output for all types of glass was approximately 22-24 million tons in 1985.[28]

Glassmaking is a multi-step process which consists of mixing a batch of dry ingredients; heating the batch until molten and uniform in composition; forming the molten glass into the desired shape; and annealing, which reduces the temperature of the product in a controlled manner in order to minimize stresses that might otherwise be retained.

Historically, natural gas has been the preferred fuel for meeting thermal energy requirements. However, the use of electricity for several processes is increasing because of the advantages of electric heating, such as increased efficiency.

This effort focused on comparing the use of natural gas and electricity for three unit operations in glassmaking: melting, conditioning, and annealing. Carbon dioxide production for each process was evaluated.

Electric Melting

Melting is the most energy-intensive stage of glass production. It accounts for 43 to 85 percent of total energy needs.[29] During this process, dry products are continually added to a pool of molten glass. Glass behaves as a viscous liquid which softens continuously as it is heated. Temperatures of 2,500 degrees Fahrenheit are typically required.

The most common furnace used for melting is the regenerative furnace, which relies on thermal convection to stir the batch as it melts, applying heat from the top. This furnace allows for continuous melting at high temperatures. Natural gas is the dominant fuel used, with an energy efficiency range of 15 to 25 percent.[30] Approximately 6.7 MBTU per ton is required to melt glass in a high-production furnace, and 12.3 MBTU per ton for a small low-production furnace.[31]

Electric melting, a well established technology, transfers electricity between electrodes submerged in the melt. The batch is melted from the center, producing little heat loss. Thermal efficiency ratings are typically about 65 percent.[32] Approximately 2.7 MBTU per ton is required for melting glass in a large electric melter and 5.1 MBTU per ton for a small furnace.[33]

Advantages of electric melting include: avoidance of air pollution, uniformity of glass, low loss of product, less trouble regaining production after a shutdown, less space requirements, etc. Disadvantages include the higher cost of electricity compared to natural gas and higher capital costs.[34]

Using the thermal energy requirement data discussed above for both the natural gas-fired melter and the electric melter, CO_2 emissions for each process were calculated. The electric melter offers an 8 percent reduction in CO_2 production over the conventional natural gas melting techniques. This represents a CO_2 reduction of 64 lbs per ton of melted glass.

Natural gas is traditionally used for two other processes in glassmaking: the "forehearth" or conditioning trough which conveys the molten glass from the melter to the glass forming machines, and for the "Lehr" or annealing furnace where the shaped glass products are reheated and then cooled to room temperature to reduce or eliminate residual stresses in the final product.

Electricity, however, is used for these processes in many plants due to careful temperature control needed for these operations. Each process is described below.

Electric Conditioning (Forehearth)

The function of a forehearth is to reduce the temperature of the molten glass from the melter to the level required for forming and to deliver glass to the forming process at a uniform temperature.

It has been documented that the electric forehearth uses 10 percent as much energy as does its gas-fired counterpart and increases production efficiency by 2 to 5 percent.[35] Other benefits include faster response to varying production demands, improved working environment because of cooler conditions, elimination of gas fumes, and lower noise levels.

Natural gas energy requirements for this process are around 50,000 BTU per ton. Assuming that the electric forehearth requires 10 percent of the energy requirements of the gas-fired forehearth, approximately 14.7 kWh per ton of electricity is required.[36] The significantly reduced energy requirements using the electric forehearth produces a CO_2 savings of about 22 pounds per ton of glass, a 53 percent reduction.

Information on the current use of the electric forehearth in the glass industry was not collected. Thus, documented market penetration statistics were not evaluated.

Electric Annealing (Lehr)

The purpose of the Lehr, or annealing furnace, is to control the temperature of the shaped glass as it cools to reduce thermal stresses. Annealing furnaces typically comprise a conveyor belt enclosed in a thermally insulated structure with provisions for burning gas. In the electric design, electric resistance heating elements are incorporated into the insulated structure.

As with the electric forehearth, energy savings of approximately 90 percent over the gas annealing furnace have been reported.[37] Several additional benefits of the electric Lehr furnace include: using the waste heat from the process, which is free from flue gases, for additional space heating; a cleaner working environment; less maintenance; accurate temperature control; and higher quality product.[38]

Since the energy requirements for this operation are about equal to the forehearth operation, the CO_2 savings were calculated to be identical. As with the forehearth, additional research in the area of market penetration is required to obtain statistics on market saturation.

FOOD, PAPER, CHEMICAL AND PETROLEUM INDUSTRIES

These industries consume a large amount of energy for low to medium temperature process heating applications. While several electrotechnologies were briefly reviewed, the freeze concentration technology appeared to offer the largest CO_2 reducing potential within this group.

Freeze Concentration

The concentration and separation of liquid materials is a basic step in many industrial processes that usually requires energy-intensive evaporation or distillation operations driven by fossil-fueled process heat. These processes are used most widely in the food, chemicals, petroleum and, to a smaller degree, paper industries.

Freeze concentration has the potential to reduce energy consumption for separation processes by up to ninety percent.[38] The process typically uses an electric motor-driven refrigeration cycle to solidify liquid fractions at lower temperatures, whereas conventional processes boils them off at higher temperatures.

Three major pieces of equipment are involved in the freeze concentration process. The first is the refrigeration unit, which cools a solution below the freezing point of one of the materials to be separated. Then a second vessel, or crystallizer, is used in which frozen crystal growth takes place. Lastly, the third is a washer/separator, in which the crystals are removed from the process solution and washed to remove impurities (See Figure 3-4).

A recent EPRI project indicates that the substitution of freeze concentration technology for evaporation and distillation in all feasible cases could lead to annual energy savings of approximately $5.5 billion, amounting to an annual reduction in steam energy use of 1.4 quads and an increase in electricity consumption of about 20 billion kWh. The study estimates that approximately 75 percent of this feasible changeover could be accomplished during the next 25 years.[40]

EPRI conducted detailed analyses on five near-term substitution possibilities including:

- milk and whey concentration in dairy industry;
- black liquor concentration in pulp and paper industry;
- caustic concentration in inorganic chemicals industry;
- alcohol concentration in organic chemicals industry; and
- benzene-toluene-xylene fractionation in the petroleum industry.

For these five applications, EPRI forecasts that freeze processes can be adopted in an average of 85 percent of the possible cases.

The energy requirements of conventional versus freeze concentration processes in these five applications were evaluated with respect to carbon dioxide production. Table 3-6 contains the results. It was found that a reduction of 39.5 billion pounds of CO_2 per year would be possible if conversion to freeze concentration were to occur in all feasible applications.

Freeze concentration could be a viable substitute for fossil-fired separation processes in a variety of other industrial applications as well. Table 3-7 lists those applications that were compiled by EPRI. Since individual

FIGURE 3-4

FREEZE CONCENTRATION TECHNOLOGY

Reference:

"Freeze Concentration: An Energy-Efficient Separation Process," EPRI Journal (January/February 1989)

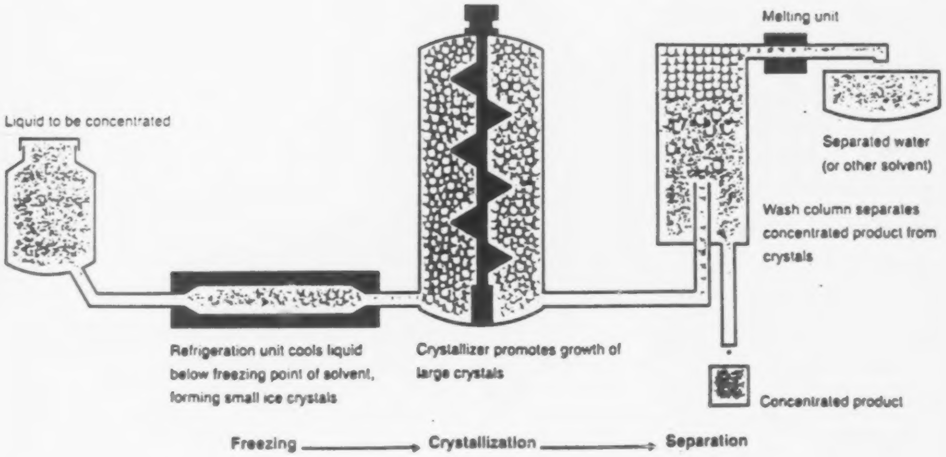

Liquid to be concentrated
Melting unit
Separated water (or other solvent)
Wash column separates concentrated product from crystals
Refrigeration unit cools liquid below freezing point of solvent, forming small ice crystals
Crystallizer promotes growth of large crystals
Concentrated product
Freezing → Crystallization → Separation

TABLE 3-6

REDUCTION OF CARBON DIOXIDE ON AN INDUSTRY-WIDE BASIS USING FREEZE CONCENTRATION OVER CONVENTIONAL SEPARATION PROCESSES FOR FIVE INDUSTRIAL APPLICATIONS

PROCESS	REDUCTION IN STEAM USE [a] (trillion Btu/yr)	ASSOCIATED CO_2 REDUCTIONS (lbs/yr)	INCREASE IN ELECTRICITY REQUIREMENTS (million kWh/yr)	ASSOCIATED CO_2 INCREASES (lbs/yr)	TOTAL ESTIMATED CO_2 REDUCTIONS PER APPLICATION (lbs/yr)
Food Industry [b]					
Milk Concentration	0.35	5.51×10^7	18.0	2.50×10^7	3.01×10^7
Whey Concentration	3.95	6.22×10^8	71.0	9.87×10^7	5.23×10^8
Paper Industry [c]					
Black Liquor Concentration	228.0	3.60×10^{10}	5175.0	7.19×10^9	2.88×10^{10}
Chemical Industry					
Caustic Soda Concentration [d]					
- Diaphragm Cell Plant	41.2	6.49×10^8	(99.0)[e]	(1.38×10^8)	6.63×10^8
- Membrane Cell Plant	.20	3.15×10^7	(.30)	(4.17×10^5)	3.19×10^7
Alcohol Refining [c]					
- Isopropanol	1.80	2.84×10^8	25.5	3.54×10^7	2.49×10^8
- Ethanol	4.24	6.69×10^8	63.0	8.76×10^7	5.81×10^8
Petrochemical Industry [f]					
BTX Fractionation	24.02	3.79×10^9	810.0	1.13×10^9	2.66×10^9
Total	303.76	4.79×10^{10}	6063.2	8.43×10^9	3.95×10^{10}

[a] It was assumed that fuels for steam and heat production include coal (40%), natural gas (40%), and oil (20%).
[b] Based on a 75% forecasted substitution rate estimated by EPRI.
[c] Based on a 90% forecasted substitution rate estimated by EPRI.
[d] Based on a 100% forecasted substitution rate estimated by EPRI.
[e] Decrease in annual electricity requirements is attributed to the ability of the freeze process to take advantage of the process heat of dilution.
[f] Based on a 67% forecasted substitution rate estimated by EPRI.

Reference: Electric Power Research Institute, Industrial Applications of Freeze Concentration Technology (EPRI EM-5232), Prepared by Heist Engineering Corporation, Wilmington, NC (June 1987).

TABLE 3-7

ESTIMATED CARBON DIOXIDE REDUCTION FROM USE OF FREEZE CONCENTRATION TECHNOLOGY FOR OTHER INDUSTRIAL APPLICATIONS

INDUSTRY/APPLICATION	CURRENT ENERGY USE (trillion BTU)	FREEZE [a] ENERGY USE (trillion BTU)	ROUGH ESTIMATED CO_2 SAVINGS (lbs/year) [b]
Food Industry			
- Beet Sugar	29	1.7	3.9×10^9
- Cane Sugar	20	2.4	2.2×10^9
- Wet Corn Milling	18	1.0	2.4×10^9
- Others	26	4.1	2.4×10^9
Chemical Industry			
- Alumina	63	2.0	9.1×10^9
- Ethylene/Propylene	50	0.78	7.6×10^9
- Phosphoric Acid	28	0.34	4.3×10^9
- Sodium Chloride	19	0.34	2.8×10^9
- Styrene	16	0.34	2.4×10^9
- Others	258	46.8	2.2×10^{10}
Petroleum Industry			
- Crude Distillation	361	61.4	3.2×10^{10}
- Vacuum Distillation	90	15.3	8.0×10^9
- Reforming	49	12.9	2.5×10^9
- Hydrotreating	77	3.4	1.1×10^{10}
- Naptha Fractionation	61	2.7	8.5×10^9
- Sour Water Stripping	27	1.0	3.8×10^9
- Light Ends Processing	17	0.68	2.5×10^9
- Others	230	16.7	2.9×10^{10}
Others Not Listed Separately	391	47.4	4.2×10^{10}
Total	1,830	221.3	2.0×10^{11}

[a] A conversion factor of 3,413 BTU per kWh was used to determine CO_2 production from the above end-uses. CO_2 produced from electric generation is incorporated in the "lbs/kWh" estimate, calculated in Section 2.0.

[b] These should be viewed as rough estimates as no data was provided on the types and amounts of energy used in conventional processes. It was assumed that coal (40%), natural gas (40%), and oil (20%) are used.

Reference: Electric Power Research Institute, Industrial Applications of Freeze Concentration Technology (EPRI EM-5232), Prepared by Heist Engineering Corporation, Wilmington, NC (June 1987).

case studies were not conducted on these applications, detailed energy data were not available. However, very rough estimates of CO_2 reductions were calculated, based on assumptions concerning the types of fuels currently in use.

It was calculated that an additional reduction of 200 billion pounds of CO_2 may be possible using freeze concentration. More specific energy requirement data on these industries is needed, however, in order to conduct more accurate evaluations.

The freeze concentration technology offers returns on investment ranging from a low of 20 percent for milk processing to a high of 80 percent for p-xylene fractionation, and thus merit further development.[41] The fundamental principles underlying freeze concentration have been developed and there have been some limited commercial applications. However, before the technology can be widely commercialized, additional laboratory pilot plant and testing will have to performed. The significant energy and cost savings that can be realized from its use will assist to further refine the technology for wide spread commercial application.

3.4. Conclusion

Significant reductions in CO_2 can be realized from the substitution of several electrotechnologies for fossil-fueled industrial processes. The exact amount of savings, however, is dependent upon several factors, the most important of which is the composition of the electric utility fuel mix which varies significantly by region.

Using the national average electric generation fuel mix as a basis, CO_2 reductions were found to exist in applications involving: the electric arc furnace; induction heating; electric glass melting, conditioning and annealing; freeze concentration; and infrared heating. Many technologies and processes were not evaluated that may offer additional CO_2 reduction. Use of induction melting and the plasma-fired cupola were not found to reduce CO_2 using the national average electric generation fuel mix as a basis. However, in regions where significant quantities of non-CO_2 producing fuels are used to generate electricity, CO_2 reductions could result.

Table 3-8 summarizes the key findings of the electrotechnology analysis. Percent CO_2 savings by process were calculated for those technologies where data were available. The overall

TABLE 3-8

SUMMARY OF CARBON DIOXIDE REDUCTIONS FROM ELECTROTECHNOLOGIES VERSUS COMPARABLE FOSSIL-FUELED PROCESSES BASED ON 1988 NATIONAL AVERAGE ELECTRIC UTILITY FUEL MIX

INDUSTRY/ ELECTROTECHNOLOGY	ESTIMATED CO_2 REDUCTIONS/UNIT	PERCENT CO_2 REDUCTION/UNIT	PROJECTED INDUSTRY-WIDE ANNUAL REDUCTION (Year Total Market Potential Realized)
Metals:			
Electric Arc Furnace	2,626 lbs/ton steel	75%	2.10×10^{10} lbs (2000)
Induction Heating			
- Billet Forging	352 lbs/ton billets	35%	Unknown
- Steel Hardening	22,818 lbs/ton steel	44%	Unknown
Induction Melting	None	None	None
Plasma-Fired Cupola	None	None	None
Infrared Heating			
- Steel Coating	2.3 lbs/1000 ft of steel coated	46%	Unknown
- Coating/Curing Lighting Poles	23.5 lbs/pole manufactured	57%	Unknown
Glass:			
Electric Melting	64 lbs/ton glass	8%	Unknown
Electric Forehearth	40 lbs/ton glass	67%	Unknown
Electric Lehr	40 lbs/ton glass	67%	Unknown
Food/Paper/Chemical:			
Freeze Concentration			
- Milk and Whey	Unknown	Unknown	5.5×10^{8} lbs (2015)
- Black Liquor	Unknown	Unknown	2.9×10^{10} lbs (2022)
- Caustic Soda	Unknown	Unknown	6.6×10^{9} lbs (2000)
- Alcohol Refining	Unknown	Unknown	8.3×10^{8} lbs (2015)
- BTX	Unknown	Unknown	2.7×10^{9} lbs (2015)
- Other potential applications (see Table 3-7)	Unknown	Unknown	2.0×10^{11} lbs (2015) (rough estimate)

industry-wide reduction impacts of electrotechnology substitution were estimated for some applications, however, market penetration data is lacking in some areas that precluded efforts to develop a total CO_2 reduction rate for the technologies evaluated.

For the technologies in which market penetration rates were obtained (i.e., electric arc furnace and freeze concentration), CO_2 reductions represent about 17.4 percent of annual CO_2 emissions from the industrial sector, or about 4.1 percent of the total man-made CO_2 produced in the United States.

The findings, while preliminary, provide a basis upon which further research can be conducted. Continued research can help more accurately quantify the CO_2 reductions of the technologies identified in this study, identify additional electrotechnologies that have the potential to reduce CO_2 levels, and calculate the total potential savings on an industry-wide basis.

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2. Ibid.
3. Office of Technology Assessment, Industrial Energy Use, Washington, DC (June 1983).
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8. American Gas Association, Industrial Sector Energy Analysis: The Steel Industry, Arlington, VA (September 28, 1988).
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26. EPRI Center for Metals Fabrication, "TechApplication: Medium and Short Wave Infrared Curing," (1987).

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28. Ibid.

29. Ibid.

30. Ibid.

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33. Ibid.

34. Electric Power Research Institute, Industrial Electrification Potential: Case Studies of the Primary Metals and Glass Industries (EPRI EA-2761), Prepared by Charles A. Berg Associates, Buckfield, ME (December 1982).

35. Burwell, C.C., Glassmaking: A Case Study of the Form Value of Electricity Used in Manufacturing, Institute for Energy Analysis, Oak Ridge Associated Universities, Oak Ridge, TN (July 1982).

36. Ibid.

37. Ibid.

38. Ibid.

39. Electric Power Research Institute, Industrial Applications of Freeze Concentration Technology (EPRI EM-5232), Prepared by Heist Engineering Corporation, Wilmington, NC (June 1987).

40. Ibid.

41. Ibid.

4.0 THE TRANSPORTATION SECTOR:
IMPACTS OF ELECTRIC TRANSPORTATION MODES

The transportation sector produces 32 percent of total man-made CO_2 emissions in the United States, or approximately 2.3 trillion pounds of CO_2 annually.[1] Two major areas of CO_2 savings potentially exist. The most obvious is direct substitution, such as replacing gas or diesel cars or buses with equivalent electric models. The other area involves an entirely different, more efficient mode of transportation for the same transit jobs.

Our analysis included evaluations of the direct substitution of electric vehicles for automobiles, light trucks, trains, and buses. From the vehicle efficiency data reviewed, significant opportunities for CO_2 reduction exist with increased mass transit. However, it was found that more research is required to conduct a comparative CO_2 analysis on the explicit reductions from mass transit since the total urban transportation use data for all vehicle types are difficult to obtain.

The analysis examined one cross substitution, that of electrified rail for trucking in containerized type shipments. All the electric transportation substitutions reviewed either are already available or will be in the very near term.

Clearly, not all possible transportation mode CO_2 savings have been identified. The purpose of this work is to indicate a general direction which might be useful in further research and policy development. Our focus is on electrotechnology substitution using the technologies most likely to be economically viable. As noted, many of the technologies have existed for years and are absorbing greater shares of the marketplace. Others are at the experimental level, but are about to emerge into the market. R&D resources, policy initiatives and the cost of electric transportation modes will influence the level and rate of market adoption.

Total CO_2 production rates for each transportation mode were estimated by deriving the energy requirements of each type, using 1988 fuel consumption estimates from DOE. The number of BTUs were based primarily on research data compiled from Oak Ridge National Laboratory from 1974, which were detailed enough to separate fossil-fueled transportation modes into categories with comparable electric substitutes. The percentage of total transportation sector energy consumption by vehicle type was then applied to actual fuel consumption data for 1988 in order to derive the CO_2 production and savings potential. It is interesting to note that current energy use patterns are very similar to patterns observed in the early 1970s, which lends additional credibility to the methodology.

Using 14 year old data may introduce some bias as a result of the changes in the relative use of autos, trucks, trains, or buses to each other since 1974. These changes, however, should not significantly alter the results since the relative percentage of each transportation type was applied to total fuel consumption in 1988 to develop overall CO_2 impacts. Carbon dioxide savings calculated vehicle type to vehicle type should be fairly accurate, even though total levels may be different from other macro studies given the engineering approach used for this study.

Table 4-1 contains the total potential CO_2 savings by transportation mode. No attempt was made to assess the market penetration rates or market saturation rates of each electric substitute, as data are lacking in this area. Conclusions drawn from the table are the estimated total technical potential. While it is infeasible that total substitution of electricity for an alternate will occur for each mode, the findings provide a clear indication of where the best CO_2 saving opportunities exist. Total savings for the modes evaluated below represent an 8.2 percent potential reduction for transportation sector CO_2 emissions, or 2.6 percent of total CO_2 produced in the United States. Each mode is discussed below, including the methodology for deriving any savings.

4.1. Passenger Autos

Passenger autos account for nearly 75 percent of all motor gasoline consumed in the United States.[2] While the automobile has eluded drastic changes in terms of pollution control, the California Air Resources Board recently adopted measures that call for phasing out gasoline-powered engines in the South Basin area.[3] If these measures are approved by the state, this could provide a catalyst for the electric vehicle market. If actions such as these continue to arise, in conjunction with ongoing efficiency improvements of electric vehicles, it is not unrealistic to assume that a significant reduction in the use of fossil fuels for automobiles can be achieved.

Efficiencies of electric vehicles currently average around 2,746 BTU/mile compared with 6,524 BTU/mile for internal combustion vehicles (see Table 4-1). For purposes of this analysis, a relatively high electric vehicle consumption of 1.24 mile/kWh was used.[4] This assessment includes battery charger to battery losses, and battery to traction losses.

TABLE 4-1
CARBON DIOXIDE REDUCTION FROM VARIOUS MODES OF ELECTRIFIED TRANSPORTATION

TRANSPORTATION MODE	BTU PER MEASURE REQUIREMENT	CO2 PRODUCED PER UNIT (lbs)	PERCENT CO2 SAVINGS	1988 TOTAL U.S. ENERGY REQUIREMENTS FOR TRANSPORT TYPE (Btus)	1988 TOTAL SECTOR CO2 PRODUCED (lbs)	TOTAL CO2 SAVINGS (lbs per year)
Passenger Vehicles						
- Automobile	6524/vehicle mile	1.141	2.09	1.05×10^{16}	1.84×10^{12}	5.3×10^{10}
- Electric Vehicle	2764/vehicle mile	1.118				
Trains (Passenger & Freight)						
- Diesel	3.23 (1/efficiency)	5.64×10^{-4}	14.89	6.56×10^{14} (net of current electric use)	1.15×10^{11}	1.7×10^{10}
- Electric	1.18 (1/efficiency)	4.80×10^{-4}				
Buses						
- Gasoline Bus	1138/passenger mile	0.199	71.86	1.05×10^{13} *	1.84×10^{9}	1.3×10^{9}
- Trackless Trolley	137/passenger mile	0.056				
- Diesel Bus	771/passenger mile	0.135	58.52	4.59×10^{13} *	8.03×10^{9}	4.7×10^{9}
- Trackless Trolley	137/passenger mile	0.056				
Trucks **						
- Large Semi-Trailer Truck	1110/ton mile	0.194	46.39	1.34×10^{15} (32% of all truck Btus)	2.34×10^{11}	1.1×10^{11}
- Electric Train	255/ton mile	0.104				
Total						1.9×10^{11}

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* Intra-city only.
** Cross substitution analysis.

These data show that electric vehicles enjoy roughly a 2.1 percent CO_2 saving over their gasoline counterparts (see Table 4-1). For passenger vehicles, this amounts to savings of 53 billion pounds per year or 28 percent of the transportation savings identified in this analysis.

Carbon dioxide savings result from a much higher utility power plant energy extraction from the fuel compared with the internal combustion car engine. In fact, utility power plants approach efficiencies in the 35-40 percent range while the internal combustion engine ranges from 10-20 percent. The electric motor also has mechanical transfer advantages converting energy directly to traction power.

The major drawback to electric vehicle use appears to be the range of travel before a recharge is required. Many scenarios for surmounting this problem have been analyzed, including a battery recharge service station, dual-fueled cars, and much greater battery efficiency to extend the range. However, other institutional barriers are also present, such as public acceptance and manufacturer allocation of research dollars.

Ultimately, the economics are best, and the practical problems reduced the most with highly efficient batteries.[5] Both the distance provided and the recharge time for such batteries are being improved while keeping their cost competitive. As these hurdles are overcome, the economies of electric cars can dramatically improve, which may make electric vehicles the vehicle of choice in the near future.

Tables 4-2 and 4-3 provide some indication of the versatility, performance and number of manufacturers that have committed to an electric vehicle production program. The table also shows that electric vehicles have greater potential efficiencies than those used in the CO_2 analysis, providing a somewhat conservative result.

Passenger autos for our purposes included cars, light trucks or other vehicles used for personal transportation. This market's most disturbing characteristic from both a gasoline consumption and CO_2 point of view is that a growing number of light trucks are being used for passenger vehicles. This has put the passenger mileage fleet average under downward pressure for the first time since the Arab oil embargo.[6] Despite this trend, the 1987 fleet average stood at an all time high efficiency of 19.17 mpg.[7]

TABLE 4-2

CHARACTERISTICS OF ELECTRIC VANS

				Projected		
	GM Griffon	G-van	DSEP	Chrysler TEVan	ETX-II	G-van
Top speed, mph	53	52	60+	70	60	62
urban range, mi	54	60-90[e,f]	52	110+	113	136
0-30 mph acceleration, secs	11.4	12.9	--	7	--	11
0-50 mph acceleration, secs	--	--	20.5	--	20	--
Payload capacity, lbs	1900	1640	1200	1200	1100+	1800
Cargo space, ft^3	208	231	100+	120	--	256
Power train	dc	dc	ac	dc	ac	ac
Battery	Pb/acid	Pb/acid	Ni/Fe	Ni/Fe	Na/S	Na/S
Year of production	1985	1989	--	1991	--	--
mi/kwh from battery, city	1.66	1.20	2.22	--	2.50	--
Reference	TVA (1988)[a]	TVA (1988)[a]	Kelledes (1988)[b]	EPRI (1987)	Altmejd & D. (1988)[c]	Angelis & S. (1988)[d]

"--" = not available. TVA = Tennessee Valley Authority.

[a] Driggens and Whitehead (1988b). The authors report ac energy consumption of 0.6 kwh/km and 0.85 kwh/km in the TVA urban cycle, and battery plus charger efficiencies of 62.5% and 61%, for the Griffon and the G-van, respectively. The difference between the Griffon and the G-van was less in the SAE J228a/C cycle.

[b] Payload and Cargo space are mission requirements. Urban range and city efficiency data from SAE J227 a/D cycle.

[c] Mi/kwh is goal; other data are from simulation. Urban range and city efficiency refer to FUDS. Performance shown here is based on current ABB-B11 Na/S battery technology of Table 3. The ABB Na/S battery projections of Table 3 would result in a longer range.

[d] Payload and cargo space data from EPRI (1987). Urban range refers to ECE urban cycle. Based on ABB Na/S battery projections of Table 3, with an improved powertrain.

[e] Urban range was originally incorrectly listed as 40 miles. For more information, contact EPRI Transportation Program (415/855-2168)

[f] EPRI EV 2019.5.89.R.

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DeLuchi, Mark A., et. al, Electric Vehicles: Performance, Life-Cycle Costs, Emissions, and Recharging Requirements, Division of Environmental Studies, University of California, Davis, CA (Pergamon Journals Ltd., 1989).

TABLE 4-3

CHARACTERISTICS OF SELECTED ELECTRIC PASSENGER VEHICLES

	ETV-1	ETV-2	EV-20	ETX-I	1987 BMW	---- Projected ---- 1990 BMW	 VW Jetta
Top speed, mph	--	62	60	60	53	75	78
Urban range, mi	up to 75	66	<75[a]	--	43-77[b]	62-124[b]	118
0-30 mph acceleration, secs	--	8	--	7	14	7	6
mi/kwh from battery, city	3.41	3.14	--	3.61	--	3.73[c]	--
Passenger capacity	4	4	2	2	4	4	4
Power train	dc	dc	ac	ac	dc	ac?	ac
Battery	Pb/acid	Pb/acid	Pb/acid	Pb/acid	Na/S	Na/S	Na/S
Approx. year of tests	1980	1980	1986?	1985	1987 on --->		--
Reference	Kurtz (1981)	AiResearch (1981)	Wyczalek (1987)	Ford & GE (1987)	Regar (1987)	Regar (1987)	Angelis & Sed. (1988)[c]

-- = not available. Top speed is maximum continuous cruising speed. Range and efficiency data for ETV-1, ETV-2, and ETX-I refer to FUDS; for Jetta, they refer to ECE urban cycle.

[a] Range is at constant speed of 25 mph.

[b] Lower range estimate at top speed; higher at 30 mph.

[c] Based on ABB Na/S battery projections of Table 3, with an improved powertrain.

Reference:

DeLuchi, Mark A., et. al, Electric Vehicles: Performance, Life-Cycle Costs, Emissions, and Recharging Requirements, Division of Environmental Studies, University of California, Davis, CA (Pergamon Journals Ltd., 1989).

It is still unclear how fossil-fueled vehicle efficiencies will change over the next several years given these recent trends. Electric vehicles, however, are becoming increasingly viable, with both vans and passenger cars already in field tests and full scale production set for some models by 1991.

4.2. Trains

Carbon dioxide savings for trains come from both freight and passenger train electrification. Most track beds are adjacent to each other or the same, making electrification more feasible and potentially less costly. The values in Table 4-1 were calculated by combining all classes of train transport, subtracting the electric freight and passenger portions to obtain the amount of energy used by diesels that could be converted to electric.

The concept of electrifying large portions of the railroad system has been discussed for years. Several studies conducted in the late 1970s and early 1980s by the Department of Transportation, Municipal Railway Systems, and several universities and industry groups have concluded that electric rail transportation is one of the most efficient and least expensive means of transportation.[8]

Rights of way to run overhead power lines normally would pose one of the more significant obstacles to increased electrified train routes. However, the existing right of way for the railroad is in most cases more than adequate to install overhead lines. One of the more difficult pragmatic issues is that for long distances, lines would necessarily need to be fed from different utilities. For shorter distances, many metropolitan systems, particularly on the East Coast, have already been electrified.

Diesel trains currently account for 10 percent of the distillate fuel used in the United States.[8] It was found that electrified rail can reduce these CO_2 emissions by 15 percent. If wholesale turnover to electric trains were to occur, 17 billion pounds of CO_2 could be saved per year, representing 9 percent of the savings identified in this analysis for the transportation sector. Not only is this a significant impact, but such a shift is more achievable in the near future than some of the other substitution options.

Electrified rail has demonstrated its viability over the past twenty to twenty-five years. Probably the major reason it is not more widely in service has been the general decline of railroads nationally and a lack of funds for capital improvements. After the oil embargo and the high oil costs of the late 1970s, rail has been revived. Even with today's lower oil prices, prospects are good for the railroads as road congestion makes rail a more attractive option.

4.3. Buses

Buses are used for many types of transportation uses ranging from providing tours to school use, and from urban mass transit to long distance travel. The nature of tours, school busing, and long distance travel do not easily lend themselves to electrification. It would be impractical to feed routes from overhead, and power/distance requirements are beyond the reach of battery and electric vehicle technology for the foreseeable future.

The remaining category, urban mass transit, is amenable to electrification in many cities. Boston is currently considering additional electric bus routes. Many other cities have remnants of overhead capability from the days of the electric trolley.

Relief from pollution and compliance with the EPA's pollution zone attainment regulations may force many cities to seriously consider this option. San Francisco, New York, Philadelphia, and Chicago all have the infrastructure to accommodate electrified bus routes. For example, Boston simply maintained some of its trolley routes, removed the tracks, and began running buses with long contact arms. These vehicles use less space than the trolley, interface naturally with traffic, and remove the obstacles in the street which were especially annoying for bicyclists and motorcyclists. These vehicles are also lighter, can hold more passengers, and are nearly silent, reducing the noise that affected residents along their routes.

Combining gasoline and diesel urban mass transit busing and connecting it to electric would yield a 4.8 billion pound CO_2 reduction. It is noteworthy that the trackless trolley yields a 72 percent CO_2 reduction over a gasoline powered bus and 59 percent over a diesel powered bus.

4.4. Trucks

Trucking is subject to many of the same constraints identified for buses. Power requirements for some truck loads are too large for today's electric vehicle capabilities and the vast majority of this transport is long distance. Intermediate sized trucks often cover routes too spread out to make any overhead electric source cost effective or practical. Much of the mid-sized truck class includes vehicles such as cement mixers, dump trucks, and other service vehicles for which battery technology is not sufficient.

Commercial delivery trucks and van-type service vehicles are ideal candidates to be replaced by electric vans. Both the weight and functions of these vehicles allow electric vehicles to be practical substitutes and, in some instances, offer service advantages. Most fleets are parked overnight in some central location, which makes service and recharge very easy to perform. Actual maintenance costs can be reduced substantially, offering reduced personnel costs as well as operation and maintenance costs. Gasoline and other hazardous materials can be reduced or eliminated from the service garage area.

Despite the potential in this area, more data are needed on how much of the commercial truck fleet these vehicles represent. Market research and survey data would be useful to help predict market penetration rates for electric van substitution in the market segment.

Containerized truck freight transport is much more easily identified. This sector accounts for about 32 percent of total truck fuel consumption. Transferring containerized freight from trucks to electric trains for this distance hauling offers significant energy saving and CO_2 reduction opportunities. From Table 4-1, electric trains use 80 percent less energy per ton mile than a diesel truck, amounting to a 46 percent CO_2 reduction. For this sector, this would potentially amount to 109 billion pounds of CO_2 saved annually, or 50 percent of the total savings identified in this analysis.

Containerized freight shipped by train may be more practical than it might seem at first glance. Federal Express's hub concept, which other businesses have applied, may prove to be the right concept for effectively tapping this option. Rail yards that would act as hubs could sort the shipments and then dispatch the assembled trains to distribution hubs. Local trucks could then pick up the freight to deliver it to the final destination.

In short, electric train transport could become a highly profitable means of freight transport. It is also a market segment that seems ripe for development by the rail companies.

4.5. Conclusion

Overall, 8.2 percent of the CO_2 produced in the transportation sector could be eliminated through an aggressive electric substitution program based on the findings of this preliminary assessment. These savings incorporate CO_2 produced for kWh delivered. However, research is still needed in terms of identifying additional CO_2 reduction possibilities and determining the timing under which such savings can be realized.

Electrified rail is an essential part of this program. It produces not only a 15 percent savings over diesel trains, but also a 46 percent savings which accrues from moving truck freight over to electric trains. Electrification of the rail system was a hot topic at DOE, universities, and consulting/engineering firms in the late 1970s and early 1980s. The impetus decreased when fuel prices dropped precipitously. With the advent of solid state switching and more effective motive transfer, the electric train is again becoming an economically viable and attractive transportation option. This option may prove to be a large step forward in pollution control and energy reduction in the future.

Electric vehicles have been gaining additional impetus from regulatory activities in California. The South Coast Air Quality Management District has approved goals for the year 2000 of a 40 percent saturation of low CO_2 emitting passenger vehicles, 70 percent for freight vehicles and 100 percent for transit buses.[7] With mass production and increasing marketplace acceptance, electric vehicles could become a competitive force sooner than expected.

While electric vehicles show savings of 2.1 percent, this result is particularly sensitive to the type of generation that is in use during the off-peak hours that might be associated with the recharging period. If non-CO_2 producing utility generation is in use, such as hydro or nuclear, CO_2 reductions could approach 100 percent. This would have a significant impact on CO_2 production in the United States, since passenger vehicles and light delivery trucks alone produce nearly 26 percent of CO_2.

However, additional research is necessary to more fully evaluate regional and utility specific fuel mixes to determine what fuels predominate during off-peak hours. If it is coal, our findings of 2.7 percent savings could be lower. If it is nuclear, hydro, or oil, the savings could be much higher.

Data on market penetration potential for all the electric transport options is needed in order to more fully address the uncertainties associated with estimates derived for each of the end uses identified. Based on this preliminary analysis, the most promising areas for CO_2 reduction would seem to be increased electrified rail, and increased competitiveness of the electric vehicle with gasoline powered automobiles. These two areas could reduce CO_2 emissions by nearly 200 billion pounds per year in the United States.

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5.0 SUMMARY AND CONCLUSION

This preliminary scoping effort found several electrotechnologies and electric transportation modes, most of which are commercially available, that produce significantly less CO_2 than their fossil-fueled counterparts. In the industrial sector, these include use of the electric arc furnace, induction heating, electric glass melting, conditioning and annealing, freeze concentration, and infrared heating. For the technologies in which market penetration rates were obtained (i.e., electric arc furnace and freeze concentration) CO_2 reductions represent about 17.4 percent of annual CO_2 emissions from the industrial sector, or about 4.1 percent of the total man-made CO_2 produced in the United States.

In the transportation sector, use of electric vehicles, trains, and trolleys were also found to reduce CO_2 levels. Overall, 8.2 percent of the CO_2 produced in the transportation sector could be eliminated through an aggressive electric substitution program based on the findings of this preliminary assessment. An attempt was made to quantify savings both on a unit process basis and on an industry-wide basis.

Additional research is needed to more accurately quantify the actual savings of electrification associated with these applications. It is likely that several other CO_2 reducing applications of electrification exist in these and perhaps other sectors as well. It is also necessary to evaluate these findings on a regional basis in order to more realistically quantify CO_2 savings based on electric utility fuel mix differences that exist across the country.

While the findings of this effort can significantly contribute to the development of strategies to reduce CO_2 levels, further research efforts will be needed to develop specific programs for national CO_2 reduction.

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TECH APPLICATION

Short Wave Infrared Curing

Published by the EPRI Center for Materials Fabrication

Vol. 1, No. 1, 1987

The Challenge: Keeping the Charm of the South Made in the USA

The [illegible] that grace [illegible] buildings [illegible] But Moultrie [illegible] that, in fact, [illegible] Moultrie to introduce [illegible] expensive [illegible]

[illegible] company was [illegible] EPA [illegible] Bill Smith [illegible] that it [illegible]

- [illegible]
- [illegible]
- [illegible] EPA [illegible]
- [illegible]

The Old Way

[illegible] conveyor and [illegible] and bases. [illegible] paint actually adhered to the columns. [illegible] In fact, there [illegible] had to be [illegible] for cleaning.

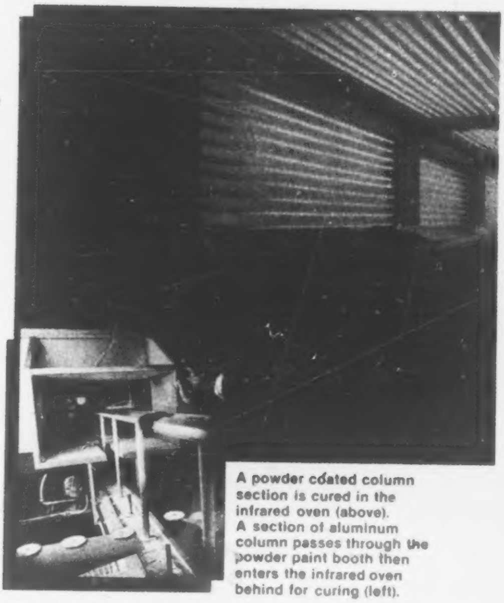
After [illegible] were [illegible] in a 40-foot-long, gas-[illegible] oven, where the paint solvent was removed — and released into the atmosphere. So much solvent was [illegible] that Moultrie was in danger of being closed down by the EPA.

Paint drying took [illegible] and only 300 parts could be processed per shift — not enough to fill all their orders.

The New Way: A Totally Different Approach

To meet all the challenges, Moultrie completely restructured their cleaning, coating and finishing system. They replaced their liquid paint with a 100% solids powder coating, which is applied electrostatically. In place of the convection oven they installed a high-intensity, short wave infrared (IR) curing oven with 6 heating zones, each with an independent 3 phase 480V power controller. And the entire line, except for part loading and unloading, is under computer control.

While each component offers certain benefits, these benefits can only be realized as part of a totally integrated system. IR is an ideal method for curing powder coatings. Because heating is so fast, the process works best under computer control.



A powder coated column section is cured in the infrared oven (above). A section of aluminum column passes through the powder paint booth then enters the infrared oven behind for curing (left).

The Results: Everything Moultrie Hoped For and More

Increased production. The same two-man, eight-hour shift now produces 10,000 rather than 300 pieces. And the finishing line is run for only half a day. The operators spend the other half of the day packaging the columns for shipping.

Material savings. Powder overspray is trapped and recycled, so that eventually over 99% of the powder is actually applied to the columns. Moultrie's powder coating material costs are the same as their paint costs in the 1960s, and 25% less than paint would cost today.

Lower maintenance. Since all the powder is applied to the columns, there is no need to close the line for cleaning.

No pollution. Because the powder is all coating material, there are no toxic fumes or solid wastes to remove, so there are no problems in complying with current EPA regulations, and Moultrie foresees no problems in meeting future standards.

Flexibility. The powder application system is designed to make it quick and easy to switch coating color.

Space savings. The IR oven itself is only 7 feet wide and 30 feet long. A gas oven with comparable capacity would have been 40 feet wide and 200 feet long, or about 40 times as large.

Faster heating. It takes only 34 seconds, at 55 ft/min, in the IR oven to cure the powder coating, whereas the old method took 1-1½ hours.

Energy savings. After installing all their new equipment, Moultrie's monthly energy costs decreased from $2,400 to $1,100.

Process control. IR emitters turn on and off very fast, so as soon as the product has left the oven, the power can be reduced. This is not possible with gas ovens because they take so long to come to temperature. In addition, sensors detect any changes in line speed and, if necessary, automatically reduce or turn off power to prevent the coating from burning.

Improved product quality. Moultrie can now offer a one year guarantee on its finishes.

Improved work environment. The IR oven concentrates the heat on the product and doesn't heat up the surrounding area.

What Did It All Cost?

Moultrie's new coating and curing equipment cost about $450,000 and their entire new installation about $1,000,000. It would have cost about 2½ times as much had they not done much of the site preparation and installation work themselves. With the increased productivity and lower operating costs, Moultrie expects the new line to pay for itself in only 3 years.

The Bottom Line: A Stronger Company and No Competition in Sight

With their new finishing line, Moultrie has improved the quality and appearance of their columns while still offering them at the 1980 price. Customers clearly appreciate this, and sales in 1985 were 25% higher than in pre-automation 1983. And the foreign competition? It is nowhere to be seen.

Other Applications of High-Intensity IR

Infrared treating is not restricted to powder coatings on metals. It is also used to treat liquid or dry coatings on:

- Appliances, car bodies and light fixtures
- Steel and aluminum strap and coil
- Flat wood products
- Glass, fabrics and paper

You can find more information on IR treating of coatings in TechCommentary Vol. 3, No 6.

Company Profile

The Moultrie Manufacturing Company, Moultrie, Georgia

The Smiths reach great heights not only in implementing new technology but also in their World War II PT Boeing Stearman.

Moultrie always welcomes visitors.

Chairman — Bill Smith, Sr.; President — Bill Smith, Jr.

Approximately 50 employees

The country's leading producer of coated aluminum architectural columns and accessories, and cast aluminum furniture

Company philosophy: Stretch your mind to the ridiculous to find solutions, move fast.

The Center for Metals Fabrication (CMF) is operated by Battelle's Columbus Division. Basic funding is provided by the Electric Power Research Institute, a nonprofit institute that conducts research and development on behalf of the United States electric utility industry. TechApplication is one of the ways the Center assists industry in implementing cost- and energy-efficient, electric-based technologies in metals fabrication and related fields.

Applicable SIC Codes

24—35,36   26—49   27—51,52   30—79   All 34-39 SICs

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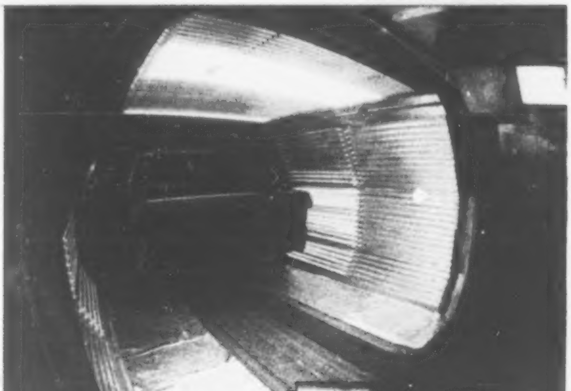
Columbus, Ohio

CMA TECH APPLICATION

Infrared Drying of Paint

Published by the EPRI Center for Materials Fabrication
Vol. 3, No. 1, 1989



Above: The IR unit drives out color-coat solvents, reduces defects, and improves the finish.

Right: A worker uses a Tension meter to measure finish reflectance.

The Challenge — The Perfect Finish

C[illegible]

[illegible]

Recent Upgrading at [illegible]

[illegible] that is conveyed through a bath that [illegible] coats all surfaces. The electrocoat is cured in a [illegible] and convection oven. Robots then apply [illegible] sealers, which are cured in a gel oven. [illegible] is conveyed into the spray booth. Anti-chip coating is sprayed on rocker panels and underbody areas. Workers enter the desired color code into a Manual Input Station (MIS) computer. The MIS directs which of nine selected colors the car is painted. Colors can be sprayed in any sequence. Now that the IR unit has been added, the MIS also controls the IR drying cycle for each car body. Three different programs [illegible] one for white and light metallics, one for dark metallics, and one for black, set the power changes for each lamp in the IR unit throughout the drying cycle.

Workers spray color coat on the interiors, inside the trunk and hood, and in the wheel wells and other recessed areas. Rotary bells and reciprocating spray equipment then automatically spray the top and sides with the new high flow color coat, a paint that reduces blemishes and is compatible with the new two-component clear coat. Before IR, the old color coats were dried in ambient air for approximately four minutes. Now the car bodies are conveyed immediately into the IR oven, where the color coat is dried in 31 seconds.

The glossy clear coat is sprayed in the same manner as the color coat and is cured in a long wave gas IR/convection oven. Quality checks are performed for smoothness, blemishes, and dirt; any defects are repaired.

The computer-operated IR unit at Chrysler utilizes sophisticated exhaust and cooling air systems. The IR unit contains 400 lamps across five zones. The IR heat warms the car body, driving out solvents and setting the paint. Currently only two zones (68 lamps) are used. The additional zones will be needed when water-borne coatings are implemented.

The Results: Higher Quality/Reliability

Chrysler continues to achieve measurable improvements.

High gloss. Chrysler measured substantial improvements in smoothness and gloss after implementing IR. The automotive industry uses a Tension meter to measure reflectance of the finish. A reading of 20 is the standard achieved only on polished black paint. With IR and new paints, Tension readings on metallic colors at the Belvidere assembly plant have increased from 16 to 18 on horizontal surfaces and from 10 to 14 on vertical surfaces. On black and white finishes, horizontal readings are up to 19 and vertical readings are 16 to 17.

Energy usage. Quality has improved at Belvidere with a minimal increase in energy costs. The output and usage of the IR unit is precisely controlled; the energy cost is only [illegible] per car.

No downtime. The IR unit is tied to the prime spray line—if the unit goes down, the entire line goes down. This illustrates Chrysler's commitment to the IR drying process. The IR unit has demonstrated impressive reliability. It has caused no downtime since production began in March 1988.

Meets future requirements. IR drying will meet Chrysler's future needs as well. When water-borne coatings are implemented, IR will be the critical factor in removing 85% of the water from the [illegible].

What About Cost?

The IR dryer unit, complete with ovens, controls and cooling system, can cost from $500,000 to $1,500,000, according to the manufacturer, BGK Finishing Systems, Inc., Minneapolis, Minnesota. The cost is dependent on line speed and installation complexity.

EPRI/CMF Sponsorship

The Electric Power Research Institute (EPRI) Center for Materials Fabrication (CMF) cosponsored the field trials for the IR unit through the CMF Electrotechnology Implementation Program (EIP). EIP targets innovative applications of electrotechnologies, such as induction, IR, and microwave heating, to prove their economic and technical feasibility in production settings.

Other Applications of IR

Chrysler is expected to expand IR for other production processes, such as two-tone paints. And, together with CMF, is researching IR curing the electrocoat.

The IR technology utilized at Chrysler can be implemented in a wide variety of industries and applications, for example:

- To cure coatings on drums, cans, and other metal containers in the metal drum, sheet, can and decorating industries.
- To cure coatings on refrigerators, freezers, cooking equipment, laundry equipment, and small appliances.
- To dry lumber and wood products, paper and allied products, and printing.

For more information on infrared drying and curing, see CMF *TechCommentary* Vol. 3, No. 6, and CMF *TechApplication* Vol. 1, Nos. 1 and 3.

Company Profile

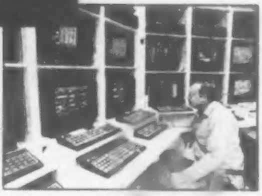
Chrysler Motors
Belvidere, Illinois

Plant Manager: S. T. Rushwin

Employees at the Belvidere plant: 4000

The Belvidere plant assembles Chrysler New Yorker and Dodge Dynasty automobiles.

Company philosophy: To be the best.



Above: Greg Bartos, paint operations manager, behind a Chrysler New Yorker. Right: The control room for the Belvidere plant paint line.

The Center for Materials Fabrication (CMF) recognizes Garry Good of PPG Industries, [illegible], for his assistance.

Commonwealth Edison Company provides electric service for Chrysler Motors' Belvidere plant.

CMF [illegible]

Applicable SIC Codes
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Senator WIRTH. Thank you very much, Mr. Morron.

Mr. Hobart, we are, as I think it was suggested to you earlier, going to put on a 7-minute clock. We have a lot of witnesses this morning, so if you could summarize your testimony in 7 minutes or less, we would appreciate it.

STATEMENT OF LARRY HOBART, EXECUTIVE DIRECTOR, AMERICAN PUBLIC POWER ASSOCIATION

Mr. HOBART. Mr. Chairman, I appreciate the opportunity to appear here. APPA supports the least-cost planning approach to meeting energy services needs of electric consumers. APPA's promotion of least-cost approaches began back in the 1970s with the creation of an Energy Services Planning Committee, and today APPA continues its efforts most prominently through an energy services exchange program which is co-funded by the Western Area Power Administration.

This program attempts to use continuously updated databases of information on innovative approaches to satisfy community energy needs, and we draw on a network of some 300 technical advisors which come from APPA's membership and I included information about that program with my statement.

APPA's membership has not had an opportunity yet to consider the fundamental question which is raised by Section 311 of subtitle (b), that is, whether it is desirable to impose any Federal requirement that state commissions and self-regulated utilities consider and adopt if appropriate for least-cost investment standards.

However, if the Committee should seek to go ahead with this legislation, APPA is certainly prepared to try to help you in refining the proposition in a way that would make it practical and useful and I should point out now several difficulties which I think would have to be addressed.

From a public power perspective, one of the serious problems faced is a requirement that every self-regulated or nonregulated electric utility must consider in a formal hearing process the adoption of a least-cost investment standard.

As the Committee knows, Nation-wide there are some 2,200 public power systems and the vast majority of these systems are quite small. In fact, the median-sized public power system is 1,696 meters. In all but seven states the systems are self-regulated. That is, they are not subject to the jurisdiction for rate purposes of a state commission, and they would be required individually to undertake the requirements that are provided for in Section 311.

It seems to us that the situation might well be handled as the PURPA statute did originally, by creating a threshold level below which individual utilities would not be required to carry out the same process as proscribed in the bill.

A second problem identified by public power is the fact that there are two different least-cost investment standards provided for in the section and it is APPA's view that a single, industry-wide standard would be more appropriate.

This is true for several reasons. One is that some, as I mentioned, not-for-profit utilities are subject to state commission regulation. That is true for seven states for public power systems and it is true in most states for consumer-owned rural electric cooperatives and the higher earnings provision of the standard provided for investor-owned electric utilities is not appropriate for nonprofit electric utilities such as these.

Furthermore, it appears that the idea of a higher earnings to be allowed for some types of investments over others, as is provided for in the IOU section of the bill is not either needed or perhaps desirable.

Senator WIRTH. If I might, Mr. Hobart, in your written testimony you also mentioned the written testimony allowing or requiring a higher rate of return for some kinds of investment rather than others, and we would appreciate your specific comments.

That was never any intent in the legislation, and I think you have either misread the legislation or it has been misdrafted because it was never the intent that there be a differential rate of return or requirement for doing that.

Go ahead, but I just wanted to insert that right now, because I would like you all to please get back to us with specifics on the language, because that was never the intent of the legislation and I was a bit surprised when I read your statement and saw that. It is probably a fault in the drafting.

Mr. HOBART. We will be pleased to give you corrective language. That is the way we read the literal words.

Senator FORD. You have an extra minute. [Laughter]

Mr. HOBART. The point is, Mr. Chairman, and you pointed out quite correctly, there should be no bias against any kind of investment. What we should be looking at is a spectrum of opportunities running all the way from demand side suggestions through cogeneration and customer services, all the way up to the supply side, and compare those in a cost-effective way to try and realize the objectives of the legislation and apparently that is your objective and that is the objective we think is appropriate.

A third point I think I would like to make is that it is APPA's view that what we are talking about in the main with least-cost standards is a planning process, and that the focus of the legislation should make that clear, that we cannot dictate the particular answers that the individual utility might want to effectuate, but what we do want to ensure is that there is a process which guarantees the consideration that is going to be given to the spectrum of opportunity that I just described, and I think it could be made clear in the legislation that that is your intent, and I assume that is what you are shooting at.

Let me talk just for a moment about the second change proposed in the bill which would be a change to PURPA and would add conservation rules and a requirement that electric utilities purchase qualifying conservation. Again, the association has not had a chance to look at this in a policy sense, but I can give you several ideas that I think might be important to you as you examine this idea.

The testimony of Steve Herod which you referred to in your opening statement, Mr. Chairman, raised some problems that I think have to be addressed as far as the legislation is concerned. There may be ways of dealing with them, but it is not quite as simple as it was with dealing with cogenerators and small power producers and Mr. Herod I think outlined some of those reasons. We are perfectly prepared, again, to assist you in examining that question, but I think that there are important points that are going to have to be covered.

Your invitation to appear here today, I should say in conclusion, asked for the additional ideas that might be useful to you that relate to the general thrust of the bill, and I think there are three things that public power systems believe might be helpful in emphasizing as you pursue this legislation.

One is the need for implementation of cost-effective standards to further the efficiency of lighting, motors and buildings, and Congress has moved in that direction, but there are greater opportunities.

Secondly, the bill clearly gives emphasis to intensification of R&D which would help give us commercially viable clean coal technology and bring on fuel cells, photovoltaics, and advanced nuclear reactors and we regard that as very important, also.

A third point to make is that we need to improve the ability to transfer technical information among utilities and customers so that we can all be aware of what the opportunities are.

Lastly, I think we need to ensure that Federal leadership is utilized in a way that is exemplified by the national power surveys that were carried out in the late 1960s and early 1970s as an effort to pull together consumers, electric utilities, government utilities and others to try and determine what is the long-term direction that the electric utility industry in this country should take. I think that would be a beneficial exercise, again.

[The prepared statement of Mr. Hobart follows:]

AMERICAN PUBLIC POWER ASSOCIATION
2301 M STREET NW WASHINGTON DC 20037 · 202/467-2900

Testimony of
Larry Hobart
Executive Director
American Public Power Association
on S.324
Presented to the
Committee on Energy & Natural Resources
U.S. Senate

November 7, 1989

My name is Larry Hobart. I am the Executive Director of the American Public Power Association, the national service organization representing over 1,750 local public power systems throughout the United States. I appreciate the opportunity to testify today on Subtitle B of Title III, the "National Energy Policy Act of 1989."

Section 311 of Subtitle B would amend the Public Utility Regulatory Policies Act (PURPA) of 1978 to require consumer-owned and regulated electric utilities to consider establishment of standards for "least cost supply measures" which would result in "adequate and reliable service to consumers with incurrence of lowest costs to society, such costs to include costs incurred by the utility and its customers and environmental costs." Section 312 of Subtitle B would amend PURPA by adding a requirement that electric utilities purchase "qualifying conservation."

APPA supports a least-cost planning approach to meeting the energy service needs of electric consumers.

APPA's promotion of least-cost approaches began in the 1970s with the creation of an Energy Services Planning Committee, followed by the association-sponsored study, "Energy Services Planning: A Public Power Strategy for the 1980s," published in 1982 by Argonne National Laboratory, and the Association booklet "Selecting Energy Services Programs for Residential Customers."

In 1985, APPA published a book entitled "The Next Ten Years: A Strategic Guide for Public Power." The book had this to say about least-cost planning, which was there referred to as "energy services planning:"

> The objective of energy services planning is to find the least-cost strategy for providing energy services to the consumer. The strategy includes consideration of a broad range of possibilities, including conventional as well as unconventional resources, load management, conservation, integration of small power production facilities and cogeneration, cutting electric usage and cost by melding two or more city services, and improvement in load factor by increasing efficiency and selective marketing.

Today APPA efforts continue most prominently through the Energy Services Exchange (ESE), co-funded by the Western Area Power Administration (WAPA). ESE uses a continuously updated database of information on innovative approaches to satisfy community energy needs, and a network of 300 technical advisers drawn from APPA's membership. An article describing public power's involvement with least cost planning is attached to this statement.

APPA remains committed to energy services/least-cost planning. Placing every option for meeting the energy service needs of the consumer on an equal footing makes sense from an environmental, economic and energy supply perspective. APPA's advocacy and public power's predisposition to meeting its customers' needs at the lowest possible cost has resulted in a least cost planning process becoming the model for many public power systems in various parts of the country.

An example of public power interest in the least cost concept is provided by the Washington Public Utility Districts Association in the State of Washington. A resolution expressing the Association's support of least cost planning, together with a definition developed by a PUD task force, is attached to this statement.

APPA's membership has not had an opportunity to consider the fundamental question raised by Section 311 of Subtitle B -- that is, whether it is desirable to impose a new federal requirement that state commissions and self-regulated utilities consider and adopt, if appropriate, a least cost investment standard. However, should the Committee decide that some standard is appropriate, APPA believes there are several difficulties with the standards contained in Section 311. I would like to highlight these for this Committee and recommend various changes.

1. From a public power perspective, a serious problem is the requirement that every self-regulated or nonregulated electric utility must consider in a formal hearing process the adoption of a least cost investment standard. Nationwide, there are over 2,200 public power systems. The vast majority of these systems are quite small. In fact the median size public power system is 1,696 meters. In all but seven states, these systems are self-regulated, that is, they are not subject to the jurisdiction of the state utility commissions and would be required to undertake the consideration of this new standard themselves. The administrative burdens imposed on all of these small systems far outweighs the potential benefits to be obtained from requiring them to undertake this analysis.

Congress recognized this problem when it enacted PURPA in 1978. The cost of service and administrative practice standards were to be considered by only the largest self-regulated systems, defined in Section 102 of PURPA as those having annual retail sales in excess of 500 million kilowatt-hours.

The new Section 115 to be added to PURPA under Section 311 of Subtitle B provides that for the purposes of this Section, the term "nonregulated electric utility" means "any person who is engaged in the local distribution and sale of electricity to any ultimate consumer and over whom a State regulatory authority does not have ratemaking authority." This definition, according to our reading, would take precedence over the size threshold provision contained in Section 102 of PURPA.

2. A second problem is the creation of two different least cost investment standards. APPA believes a single industry-wide standard is more appropriate.

One standard would be set up under a new Section 114 inserted in PURPA, and the other in a new Section 115.

- The Section 114 standard (the one to be considered by state regulatory commissions) provides that the "rates permitted to be charged by a gas utility or electric utility shall be such that the implementation of least cost supply measures permits the utility to realize higher earnings than would be realized from the implementation of other supply measures."

- The Section 115 standard (the one to be considered by the individual nonregulated gas and electric utilities) provides that "each nonregulated gas utility and nonregulated electric utility shall implement least cost supply measures," which it then goes on to define.

Presumably two different standards are proposed in the belief that the Section 114 standard calling for higher earnings was felt to be appropriate for the for-profit investor-owned utilities while the Section 115 standard was considered to be most appropriate for the not-for-profit self-regulated or nonregulated utilities.

The fact of the matter is, however, that some not-for-profit utilities are subject to state commission regulation. As I mentioned previously, a limited number of states commissions regulate local public power systems. A significantly larger number of state commissions regulate the retail rates of rural electric cooperatives. The "higher earnings" provision is not appropriate for these not-for-profit systems. APPA believes that this argues strongly for a single, uniform standard.

Of the two standards contained in S.324, the Section 115 standard is most appropriate. To require that "higher earnings" be allowed for some types of investments over others injects a bias into the planning process and thus distorts a true least cost analysis. It also seems that this "higher earnings" mandate is inconsistent with the standard's definition of "implementation of least cost supply measures." This term is defined to include the concept of "lowest total costs to society." It is difficult to understand how "higher earnings" can result in "lowest total costs."

We are aware that many for-profit investor-owned utilities have argued that there is not a sufficient financial reward for pursuing a least cost approach. However, if a least cost approach is in the public interest, then the only condition that should be imposed is that in the pursuit of this public interest goal utilities are not financially disadvantaged.

In addition, we question the premise of the IOU argument that an additional financial incentive -- higher earnings -- is required. As Deputy Under Secretary Stuntz advised this Committee:

> "Although some type of incentive may be appropriate in some cases, DOE is unaware of any analysis suggesting that the proposed standard contained in Section 311 is necessary to encourage least cost planning. Absent a detailed analysis of individual regional resources and needs, customers may pay more than necessary for investments in demand-side management projects. State and local authorities clearly are in the best position to determine the proper rate treatment for supply projects of all types initiated by the utilities they regulate."

In APPA's view, there should be no bias against investments in such least cost measures as conservation and other means of demand reduction. But there should be no bias for such investments either. The provision for "higher earnings" should be eliminated.

3. While the Section 115 standard is more appropriate than the Section 114 standard, in fact neither standard addresses the real problem. The problem, to the extent that there is one, is that not all utilities are engaged in the proper process to determine how to meet their customers needs in a least cost manner. Thus, rather than demanding that utilities "implement least cost supply measures," the focus should be on setting forth an outline of the process utilities should consider as they decide what mix of supply and demand side solutions are best suited to their own needs.

Many public power systems are applying a "5-E Test" to suggested demand-side and supply-side solutions:

- Is the choice efficient -- does it represent the most output for the least input?

- Is it effective -- could you carry it out in a practical way?

- Is the result equitable -- will it be perceived as fair to all classes of customers and the community?

- Is it economic -- will it produce the required revenue stream?

- Is the effect environmentally acceptable -- does it meet regulatory requirements and local mores?

Many utilities, both public and private, as well as some state commissions, have a least cost planning process in place. Legislation addressing this issue, if any, should recognize this fact. PURPA Section 124 provided that proceedings undertaken prior to its enactment that substantially conformed to the rate or practice standards were to be deemed as satisfying the statutory requirement. A similar "grandfather" provision would be appropriate in this case as well, if S. 324 is enacted into law.

The second change to PURPA under S.324 would occur by adding conservation rules and a requirement that electric utilities purchase qualifying conservation to existing requirements contained in PURPA Section 210. Again, APPA has not had an opportunity to place this proposed amendment of PURPA before its policy-making group for a reaction.

However, J. Steven Herod, Director of the Office of Electric Power Regulation, Federal Energy Regulatory Commission testified at length on the implementation, pricing and equity issues raised by Section 313 during this Committee's hearing on October 26, and raised questions which APPA believes must be addressed. He noted issues which would require:

- Establishing a baseline to determine real conservation.

- Dealing with potentially millions of qualifying conservation entities.

- Verification that conservation would not occur "but for payments received.

- Ensuring that demand reduction in one place is not offset in another.

- Collection of load data before and after "QC" certification.

- Developing methods to ensure conserved load is not reimposed on the system.

- Determining whether electricity is conserved by switching to another energy input.

- Deciding whether every saved kilowatt is equal to new capacity kilowatt installed.

These are practical problems which must be addressed. They are more difficult of resolution than those associated with utility purchase of power from small power producers and cogenerators because the end product cannot be defined so closely, e.g. a number of kilowatts of capacity of kilowatt-hours of electrical energy can be counted but energy conservation must be estimated.

This does not mean that savings through enhanced efficiency and demand-side management in the electric utility industry should not be promoted and pushed. It should. Similarly, increasing attention is required to insure that power production and dissemination is carried out with proper protection of our environment. The question is: How to do it best?

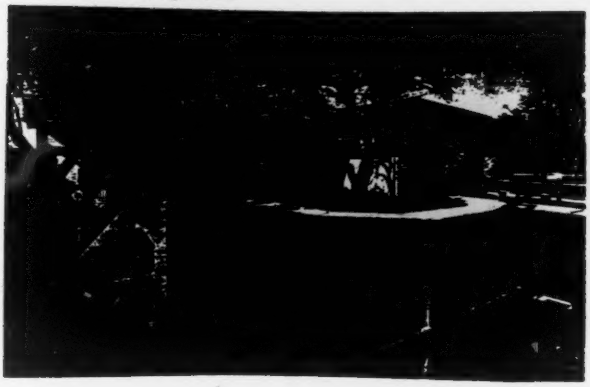
One way is the imposition of cost-effective standards to further improve the efficiency of lighting, motors, and buildings, and the intensification of R&D to give us commercially viable clean coal technology, fuel cells, photovoltaics, and advanced nuclear reactors.

Another is to improve the transfer of technical information so that both utilities and their customers are aware of the technologies and techniques which they can employ to better protect their pocketbook and their atmosphere.

And a third is to employ Federal leadership in carrying out another National Power Survey, where teams of utility, consumer, environmental, and government experts could chart the course for a power supply industry that would move us into the 21st century with assurance of a strong electric infrastructure with optimum efficiency, which is the economic/environmental answer of choice.

Attachments

Learning Least-cost Planning



The Modesto (Cal.) Irrigation District saw credits for energy-saving building techniques in new homes as "the least-cost way to defer growth of that peak," said Gordon W. Ryan, Modesto's energy management programs manager. Homeowners there receive credits of $130 to $475 on their electrical bills if their homes have double-pane glass, thermal mass, R-30 ceiling insulation, R-19 wall insulation, reduced east-or-west facing glass, exterior shade devices or energy-efficient air conditioners. Modesto hopes that at least 40 percent of the 1,000 to 2,000 homes built in the district each year will be Power Saver Homes, each saving about one kilowatt of demand.

Photo courtesy Modesto (Cal.) Irrigation District

by DAN LEWIS and LARRY BRUNEEL

Contributing editors of PUBLIC POWER. *Lewis is* APPA *director of technical services and Bruneel is* APPA *staff engineer.*

REAL TIME, UNISEX, FAST FOOD, TURBO, instant replay, supersaver, least cost. Wait a minute! *Least cost*? You recognize a list of buzz words when you see one, sure. But least cost?

It is not in the same class as unisex and turbo, but least cost is fast becoming a part of electric power jargon. Like many other newly coined terms, it appears likely to change the way we think and talk about some of our most important activities.

The term "least-cost planning" grew out of "The Least-Cost Energy Strategy," a phrase coined barely seven years ago by Roger Sant and his associates at the Energy Productivity Center associated with Carnegie-Mellon University in Pittsburgh, Pa. Sant and others later formed Applied Energy Services Inc., a consulting firm that specializes in least-cost energy analysis. To say that the term has attracted attention would be an understatement. It has created a new item in the repertoire of consulting firms; it has been cast in bytes in computer models and funded by a specific congressional appropriation.

Several states have adopted the requirement for a "least-cost plan" as a prerequisite for requests for rate increases by electric utilities. That is quite a stir to be created by a few little words. APPA has a substantial program under way in least-cost planning, and some member utilities are using the concept on their own systems.

Until about 15 years ago, electric utilities enjoyed a long trend of decreasing costs. Advancing technology, economies of scale, low fuel prices, and competition among suppliers all contributed to a favorable cost trend. To consumers, electricity seemed to be a low-cost commodity. Utilities appeared to be doing a good job by expanding their capacity with more efficient facilities.

There seemed little reason then to ask whether utility planning was done on a least-cost basis. But when costs went up, beginning in the early 1970s, consumers and regulators began to question whether utility planning had been as careful and comprehensive at it had seemed to be.

Planning Scope Broadened

The *new* least-cost planning covers more than the traditional supply factors of power production facilities, fuel, transmission lines, and distribution equipment. On the customer side, it covers more than kilowatt-hours delivered. What the advocates of least-cost technology have said is, in essence, that traditional utility planning does not necessarily give the right answer if one takes a broader view of both energy supply factors and energy consumption factors.

The issue is not simply the cost of pro-

For electric utilities, least-cost planning seeks to supply present and future energy-related services needed by consumers at the lowest possible cost consistent with constraints imposed by government and society related to matters of health, safety, environmental protection, scope of operations and taxation.

ducing kilowatt-hours, but recognizing the limitations of the traditional way of viewing the electric power market. By opening up both the supply and consumption ends to more competition, with less regulation, advocates say, market factors will work to make the overall process more efficient.

In its origins, the least-cost concept was a least-cost *energy* strategy, not limited to electric power, addressed to *national* energy policy, not the planning work of individual suppliers. The concept did not imply a direct criticism of how utilities go about planning, but rather proposed that a more broadly competitive environment for all energy-related services would lead to greater efficiency in meeting consumer needs.

For electric utilities, we believe least-cost planning should be defined like this: "Planning to supply present and future energy-related services needed by consumers at the lowest possible cost consistent with constraints imposed by government and society related to matters of health, safety, environmental protection, scope of operations and taxation."

Those constraints differentiate electric utilities from the original proponents of least cost, who were national policy strategists. Electric utilities must accept health, safety and environmental regulations. They offer comments on them, to be sure, but accept that governments speak for the people in these matters.

As to constraints on scope of operations, again, the policy strategist may prove that more efficient appliances will benefit the entire energy-related economy, but utilities cannot force customers to accept them. Utility incentives may influence consumer choices, but utilities do not make those choices. Nor do they make the tax laws, yet government tax policy influences decisions by energy producers and consumers, and therefore alters the competitive environment.

Given the constraints, does least-cost planning offer options for electric utilities that can expand the horizon of traditional planning? For many public systems, the answer appears to be an emphatic *yes*. The key lies in the definition, in the words "energy-related services."

A recent publication[*] summarized least-cost strategy as "meeting the need for *energy services* with the *least costly* mix of energy supplies and energy efficiency improvements." Least cost implies considering both the supply side and the demand side of utility operations. Utilities have traditionally been extremely conscious of supply cost factors. Therefore, for most utilities, what is new about least-cost planning is its requirement to reevaluate customer demand in terms of energy services rather than merely electricity. Various customer needs—home comfort, industrial process heat, reliable power for office machines—must be looked upon as opportunities for providing service at lower cost through efficiency improvements.

Consider home comfort: Can heating and cooling be supplied at lower cost using improved insulation, heat pumps or load management? Industrial process heat: Can it be made more economical with a dual-heating system or with cogeneration? Office machine power: Can its required high quality be assured with local control equipment, so that savings can be realized elsewhere on the distribution system? These are the kinds of questions that least-cost planners must ask.

Four-Step Process

If you see a process emerging here, you are on the road to Least-cost City. The process has four basic steps:

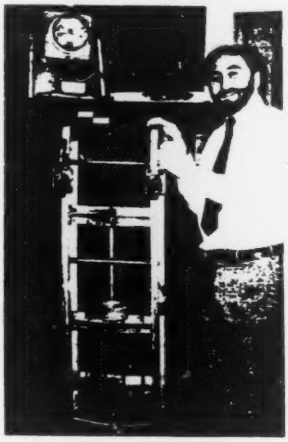
- identify the *energy services* customers need, in functional (not necessarily electricity supply) terms;
- develop the list of *options* that may be available to provide the services, using new technology, new financial or rate ideas, new marketing approaches and new supply arrangements;
- *compare the costs* associated with various options, and identify the least-cost combinations;
- develop a *management plan* to move toward greater energy efficiency through use of least-cost strategies.

The process may not be easy; some options may startle utility management.

For example, if heat pumps and other efficient appliances can be shown to offer lower cost in the long run, can the utility overcome builder resistance by "buying down" new-home costs, with recovery in rates? In a dairy-processing plant, could the utility offer to install *and own* an electric boiler alongside an existing gas-fired unit, offering attractive "valley-filling" rates?

Supply options also form part of the picture. Typically, utilities have already studied them. But technology is changing and, particularly now when many utilities have excess capacity, new forms of energy purchase agreements may offer special savings.

Different utilities will obviously apply least-cost planning principles to suit their own situations. Depending on the strategic goals of the utility, they may pursue alternate bulk power supplies, their own generation, conservation, load management or any of a number of other energy service options. After defining their universe of options, the utility can compare them on a present-worth or other same-unit basis to determine which offers the



Robert Toombs, general manager of the Washington (Vt.) Electric Co-op, proudly displays the co-op's new ultra-high efficiency Sunfrost refrigerator. The co-op is metering consumption of the new refrigerator as part of its research into energy-efficiency supply options.

Photo by Paul A. Cillo, Energy Solutions.

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[*] CREATING ABUNDANCE: AMERICA'S LEAST-COST ENERGY STRATEGY, *R. Sant, D. Bakke, and R. Naill, McGraw-Hill, New York, 1984.*

lowest-cost service. Whether this analysis is formal and comprehensive or informal and limited is not as important as the willingness of management to consider alternatives. Only by comparing the status quo to other options can a utility discern if it is offering least-cost service to its consumer-owners.

North Attleboro, Mass., controls 98 percent of the water tanks in its territory and three other major loads.

Approaches Differ

Some consumer-owned utilities are investigating least-cost options on the demand side of their businesses. Boulder City, Nev., with about 5,000 electricity customers in a growing community with high peak period costs and capacity needs in the near-term future, is one of them. After reviewing what could help on the demand side, Boulder City decided on a joint program of residential energy audits with low-cost weatherization and load management.

Oconomowoc (Wis.) Utilities, outside Milwaukee, serves about the same number of customers, but that system's approach to demand-side management is wholly different. The utility retained a consulting firm to work on energy-saving ideas with one local industrial firm and has written individual letters to each of its other industrial and commercial customers to let them know this work is going on. After the energy management program is in place for large power users, utility director Carl Melchiors wants to move on to similar programs for residences and public buildings. The utility will also look at line loss reduction and street lighting.

In east central Vermont, Washington Electric Cooperative, which serves 5,500 customers, commissioned a report on demand-side options that identified more than 2,700 kW of demand savings, equal to almost one-quarter of the utility's total system peak. Programs under investigation include: refrigerator replacement, residential lighting, security lighting, hot water heating, an electric heat package and school efficiency programs.

The cooperative proposed to buy "power" in the form of energy efficiency from its members by installing—free of charge—insulation, high-efficiency appliances and new lighting. This approach provides utility control over the timing and amount of energy savings. Customers benefit because they incur no financial obligation.

North Attleboro (Mass.) Electric Department has used mandatory load management since 1977. Its winter peak is now about equal to the summer peak; the municipal controls about 1.5 MW of the 25-MW winter peak.

North Attleboro identified electric water heaters as the primary target for load management, and controls 98 percent of the water tanks in its territory. Other loads under direct control are: commercial/industrial central air conditioning, an offpeak heating storage system and an all-electric high school. Of the eight schools in the community, the all-electric high school with load control had the lowest energy cost on a per-square foot basis. The other seven all used fuel oil. Uncontrolled, the high school would add 500 plus kilowatts to the winter peak. The load-control system is tied into the school's own load-management system.

Osage (Iowa) Municipal Utilities offers one of the best examples of using conservation as a least-cost resource.* Its multifaceted program includes:

- free use of test meters to record water-heater usage;
- a hand-held infrared scanner which shows where heat is lost in homes and businesses, and locates loose or corroded electrical connections in the distribution system;
- aerial thermograms of residences and businesses;
- conversion to high-pressure sodium streetlights;
- installation of load-management devices to cut off central air-conditioner compressors and electrical water heaters at intervals; and
- energy fairs and other customer information programs.

MANUFACTURERS HANOVER

This announcement appears as a matter of record only.

$46,245,000
Utah Municipal Power Agency

Electric System Revenue Bonds,
1987 Series A

Manufacturers Hanover Trust Company acted as financial advisor for the above transaction.

January 1987

The Investment Banking Group

See "Committed to Conservation," by Weston D. Birdsall, PUBLIC POWER, July-August 1980, p. 18, and "Negawatts—Rx for Megagoofs," by Amory B. Lovins, PUBLIC POWER, March-April 1986, p. 15.

Municipal utilities have more motivation and opportunity for least-cost options than private utilities do.

Despite growth of local industries, and addition of new businesses, the Osage electrical load has not increased for more than eight years. General Manager Weston D. Birdsall estimates annual savings of $1,760,000 for the municipal's 2,000 customers.

Although demand-side factors get most of the emphasis in the new least-cost planning, supply factors continue to be important. David W. Penn, general manager of Wisconsin Public Power Inc., a joint-action agency, has underscored the importance of planning now for long-range power supply, because smaller customers risk being told to go somewhere else when the power glut recedes.

"Be prepared for current suppliers to alter their costs to you as you start to shop around or plan your own generation," said Penn. "Current suppliers may try to lure you back with lower demand charges or block a new deal with exorbitant transmission rates.*

APPA and Least Cost

APPA's promotion of least-cost approaches began in the 1970s with energy services planning committees, followed by the association-sponsored study, "Energy Services Planning: A Public Power Strategy for the 1980s," published by Argonne National Laboratory. Today APPA efforts continue most prominently through the Energy Services Exchange (ESE), cofunded by the Western Area Power Administration (WAPA). ESE uses a continuously updated database of information on innovative approaches to satisfy community energy needs, and a network of 300 technical advisers drawn from APPA's membership.

The Boulder City program mentioned earlier is in part a result of the WAPA-funded Energy Services Exchange program. In this case, WAPA provided for a "peer match" meeting between Boulder City planners and Birdsall of Osage, Iowa, to help firm up plans and develop specific strategies.

A larger organization that also took advantage of the peer match idea is the Lower Colorado River Authority. LCRA provides power to 45 rural electric cooperatives and small municipal electric systems in south central Texas. LCRA called the Energy Services Exchange to information on load management programs and Good Cents home award programs for new construction. Lower Colorado was matched with Lee County (Fla.) Electric Co-op, a utility with extensive experience in both program areas. LCRA picked up the travel costs to bring the energy services director from Lee County to present a day-long seminar to LCRA planners and employees.

In a growing suburb of Phoenix, Ariz., the Mesa Electric Utilities Department hosted a demand-side planning workshop for other electric systems in the state. Mesa followed up with a meeting with Gainesville, Fla., and Cedar Falls, Iowa, utility staff, to develop guidelines for a commercial audit program with demand-reduction emphasis. Mesa's new SCADA (supervisory control and data acquisition) system monitors the effectiveness of programs.

In addition, many of the association's DEED (Demonstration of Energy-Efficient Developments) projects deal directly with least-cost planning.* APPA also helped form the National Coordinating Group on District Heating and Cooling/Community Energy Systems.

Municipal Motivation

Special factors may affect a publicly owned utility's consideration of least-cost options. Because such a utility is an agency of government, it may be motivated to support local government policies in its facilities planning to a far greater extent than would a large investor-owned utility. The need to stimulate local employment, use locally produced building materials, and adhere to community aesthetic standards are examples of such factors.

On the other hand, publicly owned utilities may have more flexibility in offering innovative services than larger utilities. Because publicly owned utilities are regulated by local government representing the citizens who own the system, in most states they are not limited by the rate design policies of a state regulatory commission. This has important implications for least-cost planning, because rate incentives are a vital aspect of evaluation of load management, cogeneration, joint utility-customer financing of customer-site facilities, and various other least-cost options.

The method by which consumer-owned utilities evaluate their energy options may differ. Traditional evaluations rely on a comparison of direct costs. For a local utility, however, conservation and self-generation create direct and indirect jobs and retain the community's energy expenditures in the local economy. Such benefits may tilt the scale in favor of some of the more broadly construed least-cost options.

Reducing the Risk

A difficulty that all utilities share in least-cost planning is uncertainty regarding future trends in both cost and demand, and, in particular, uncertainty in the future impact of specific least-cost strategies.* There is no way to eliminate this uncertainty. It is important to recognize, however, that the risk associated with uncertainty is itself one of the costs to be considered. An element of least-cost planning, therefore, is to reduce risk.

Risk reduction may be accomplished by *balance* in option selection, to avoid over-reliance on one or two major choices; by *sharing* risk, through joint action, on the supply side, or through joint financing, with customers, on the demand side; or by *compensation* for unanticipated effects, through, for example, rate structures or incentives that may be changed as the need arises.

Whatever the means that may be available to reduce risk, it is important to include, in a least-cost planning procedure, an analysis of the degree of uncertainty associated with both future energy requirements and expected responses to least-cost strategies.

In summary, the least-cost process is here to stay. If it moves electric utility thinking even a little bit more in the direction of serving customers in the best possible way, we will all benefit. ●

**For an elaboration of Penn's views see "Transmission Scene Shifting,"* PUBLIC POWER, *January-February 1986, p. 10.*

**See "*DEED *Speaks Louder than Words," by Michael K. Bergman,* PUBLIC POWER, *November-December 1986, p. 35.*

**One of the modules of* APPA's *PowerManager software, is Demand-Side Management* (DSM). *This program can assist in evaluating options for least-cost planning. See "PowerManager Software Available," by Michael K. Bergman,* PUBLIC POWER, *November-December 1986, p. 31.*

RESOLUTION ADDRESSING LEAST-COST PLANNING BY PUBLIC UTILITY DISTRICTS

WHEREAS: In recognition of the importance of prudent energy planning, the Washington PUD Association assembled a task force to review and recommend to the association appropriate guidelines that public utility districts may observe when considering the preparation of least-cost plans; and

WHEREAS: The task force determined that least-cost planning is a process for identifying the lowest-cost method to satisfy projected power needs utilizing a combination of supply side and demand side resources; and

WHEREAS: It is recognized that the State of Washington and the Pacific Northwest Power Planning and Conservation Act have established priorities for future energy projects and resources on a least cost basis as follows: first, conservation; second, renewable resources; third, generating resources utilizing waste heat or generating resources of high fuel-conversion efficiency; and fourth, all other resources; and

WHEREAS: A least-cost planning method involves a determination of the range of future electrical power needs for the utility; review of cost-effective potential resources available through conservation, acquisition, construction, power purchase, etc.; and development of a resource portfolio to satisfy the utility's projected needs at the lowest cost; and

WHEREAS: Such a planning process must be sensitive to environmental values, laws and policies;

NOW, THEREFORE, BE IT RESOLVED that the Washington PUD Association encourages its members to continue to utilize least-cost planning methodologies as part of their ongoing responsibilities when making new resource decisions, and to continue to utilize the public hearing process.

Adopted by the:

Washington PUD Association
Board of Directors
Seattle, Washington
November 18, 1988

Resolution 88-H

Least Cost Planning Report
Presented to the Washington PUD Association Board of Directors
October 21, 1988

Early in 1988, President McMillen asked that a task force be assembled to review and recommend to the Association a course of action, or a position, on potential legislation to require publicly-owned utilities to utilize Least Cost Planning as part of their resource acquisition or development decisions.

The committee selected for the task included Chairman Jerry Copp, Chelan County PUD; Howard Richmond, Cowlitz; Eldon Landin and Ken Pflueger, Douglas; Charles Earl, Snohomish; Harlan Warner, Okanogan; Dave Muller, Lewis; and Jim Sanders, Benton. Steve Johnson and Betty George were also helpful with arranging and conducting the meetings.

The committee met twice in Seattle and again by mail to review and comment on the draft of this report. The committee members have reviewed and discussed several Least Cost Plan reports that we are aware of, reviewed a number of papers and other literature describing Least Cost Planning, methodology, and Public Utility Commission and legislative reports. The observation of the committee was that the definition of Least Cost Planning and the art of development and use of this process are still evolving.

The committee then discussed the relationship of the Least Cost Planning process with the Environmental Impact Statement Process. The conclusion was that in most cases, Least Cost Planning is an important portion of any resource acquisition EIS. Future EIS's that do not include a Least Cost Plan in all likelihood would be challenged as inadequate. Another conclusion was that in cases involving an EIS it was certainly unnecessary for legislative mandate for a separate Least Cost Plan.

Part of this discussion included the thought that in addition to the EIS process, the permitting processes of the Energy Facility Site Evaluation Committee, Corps of Engineers, Department of Ecology, water quality Permits, other public processes, and the development of the Official Statement necessary to develop and finance any new resources all lead to assure that a least cost and feasible plan will be developed and that further regulation should not be necessary.

Another concern discussed, but only partially addressed, was the imposition of the Utilities Transportation Commission or Washington State Energy Office regulation and/or oversight that would infringe upon the commissioners' rights and duties to direct the utility. It was the consensus of the committee that, if the Association adopted the recommendations regarding Least Cost Planning, the need for legislation would then be unnecessary.

There was some discussion concerning the details of proposed legislation. In the end, it was felt that the best alternative was no legislation and, therefore, no recommendations for legislation were developed. The topics were:

(a) threshold for requirement of Least Cost Planning.

(b) how and what regulation was appropriate.

(c) definition of Least Cost Planning.

Least Cost Planning - Definition

Least Cost Planning is a process for identifying the lowest cost method to satisfy projected power needs utilizing a combination of supply side and demand side (conservation) resources. The planning process should include analysis of a utility's future loads and potential resources, giving consideration to costs, availability, reliability and other factors to determine the optimum combination of resources to ensure the utility's ratepayers a reliable power supply at low cost. The analysis should involve:

(1) determination of the range of future electrical power needs for the utility,
(2) review of cost effective potential resources available through construction, acquisition, power purchase, conservation, etc., and
(3) development of a resource portfolio to satisfy the utility's projected needs at the lowest cost.

The following are guidelines for implementing a Least Cost Plan as defined above:

1) Determination of need for resources.

Develop a range of forecasts of future energy needs using techniques which account for estimated changes in consumption based on customer response to a variety of variables. Variables which should be included are economic and demographic projections, price of alternative fuels, and price of electricity. A range of forecasts is used to address the uncertainty associated with variations in possible future events.

2) Selection of cost effective resources.

Cost effectiveness is a function of need, relative cost, reliability, and availability. The cost effective test should identify those resource options which are forecast to be reliable and available within the time needed at an estimated cost that is no greater than that of the cost of similarly reliable and available alternatives. Priority shall first be given to conservation, second to renewable resources, third to generating resources utilizing waste heat or generating resources of high fuel conversion efficiency, land fourth to all other resources. To evaluate the cost effectiveness of the resource options available to the utility, the following evaluation criteria should be used.

(a) Commercially available technology - The technology for conserving or producing electrical power must be commercially available.

(b) Predictable cost and performance - The technology must sufficiently demonstrate that its cost and performance characteristics are predictable.

(c) Competitive cost - The resource must be cost competitive using currently available technology.

4. Demonstrated resource base - The estimates of the amount of capacity and energy available from a given resource require a confirmed primary energy source such as coal, falling water, or wind.

5. Institutional feasibility - Development of the resource must not be currently constrained by legal, financial, regulatory or other institutional barriers.

6. Environmental acceptability - The resource must be environmentally acceptable and capable of complying with current environmental policies, laws, and regulations of the federal, state and local governments.

7. Lost Opportunity resource - A resource which, if not acquired or otherwise secured now, will no longer be available and cost effective.

3) Development of resource portfolio which will satisfy the need and cost effective criteria.

From the forecast of energy needs and the resources which meet the cost effective test, a portfolio of resources is developed to satisfy the forecast need under the range of forecast scenarios. The specific resources are prioritized based upon the evaluation criteria. In development of the resource portfolio important areas of consideration should include flexibility and diversification to address the uncertainty of load forecasts, resource costs, fuel prices, economic conditions and lost opportunity. The resource portfolio can be varied to meet the range of forecasts using the lowest cost resources according to priority to provide the most reliable and lowest cost supply for the utility and its ratepayers.

Senator **Wirth**. Thank you very much, Mr. Hobart. We look forward to receiving your comments on the drafting.

Dr. Cicchetti?

STATEMENT OF DR. CHARLES J. CICCHETTI, DEPUTY DIRECTOR, ENERGY AND ENVIRONMENTAL POLICY CENTER, JOHN F. KENNEDY SCHOOL OF GOVERNMENT, HARVARD UNIVERSITY

Dr. **Cicchetti**. Thank you, senator. I would like to begin by commending this Committee for the leadership it has shown on the global warming and the confluence of energy and environmental policy. I think that given the kind of problems that this Nation and the world faces, this Committee is doing a great deal of effort filling the void and showing leadership in addressing these issues.

Unfortunately, the Committee is engaging in what I will start to explain as a strong difference of opinion between electric utilities on the one hand and a growing number of state regulators on the other, and it comes together very succinctly when one thinks about the conservation, least-cost planning and regulatory reform debate.

What I would like to do is to share some ideas and some insights that I have had since I have been a consultant to the industry and a former regulator and I think I'm relatively well-received in both camps in terms of at least telling me what they think about these issues.

The typical strategy for an electric utility is to do three things: to deny that there is any load growth; to avoid a rate case at any cost; and most of all to plan the future by having somebody else provide the electricity if it is needed, and then to wrap themselves in the mystery of great distrust for regulation and really, unless they are in the same room, for regulators themselves.

On the other hand, we have an increasing number of state regulators who have come to the conclusion that there is a fundamental problem with regulation as they have been enforcing it, using it for the last hundred years, and in fact the National Association of Regulatory Utility Commissioners, has passed an opinion, or passed a motion, that basically when you cut through it, as my friend David Moscovitz is very much willing to say, essentially admits that state regulators think that regulation stinks.

The main reason they think it stinks is that profits are tied to sales, and as long as profits are tied to sales there is going to be a momentum and a tendency to expand profits by, in fact, making the system grow.

Part of that growth in sales is a focus on what I would think of as the rate base on the system. If we are going to be serious about least-cost planning, if we are going to be serious about conservation, that fundamental weakness of rate-based regulation has to be addressed.

An increasing number of state regulators are, in fact, recognizing that you cannot just focus on least-cost planning. You cannot just focus on the issue of conservation. You have to fundamentally address the issue of regulatory reform.

In some states that is going to mean legislation. At the Federal level, it may indeed mean legislation, and these are the issues that I think the Committee in the future is going to have to address.

In order to understand the debate on conservation—that is, why there is this strong conflict of opinions, it comes down to two very believable schools of thought. The first school of thought says the purpose of regulation ought to be to get the prices right and just get out of the way and let the market work.

Fundamentally, as an academic economist, I accept that issue, but I tend to think that it is more meaningful in those markets that I do not know much about. I think we can solve the Nation's education problems and drug problems with market solutions. However, when it comes to electricity and environment and energy, something I know a great deal about, I come to the conclusion that it probably is not as simple as letting the market work.

The reason is that a second school of thought has also an awful lot to commend to itself, and that is one that concludes that the electricity market is just shot full of market failures and externalities—market failures in the form that customers do not know what will work when it comes to conservation.

They do not know what price to pay and what things should cost. They do not know whether their discount rate makes sense relative to the discount rate of either the utility or the society, so we do not see conservation taking place, even though we do the arithmetic and it says it is out there and we should be doing a lot of it.

My notion is, that if we put together these two forces, we can enliven the utility industry to think that they might make some money if they go into the conservation business, pick up on the theme of regulators understanding that regulation has to be changed.

So we do not reward sales, but we reward the production of services that are useful for society in the form of, whether it is conservation or electricity or whatever it might be, but we reward those services directly. We should be forming a system that will make a market. We should not accept market failures as an inevitable reality. We in fact should make a market.

If we recognize the fact that people in the conservation market just do not know what will work, they also do not know what things will cost, and there is probably a significant discount rate between what an individual has and what a utility has, all of that should be plenty of room for a utility to go out and start to make a reasonable living providing energy services and not simply finding their profits tied to kilowatt hours.

I have been telling utilities around the country that—and regulators as well—that the time for debate has ended, and really two simple slogans would characterize what should be the theme for utilities and for regulators. The first of these is to just go out and do it. Stop debating and put together a pragmatic program that will fill the need.

Second is to recognize that we cannot make these things up in advance. We in fact have to recognize that we do not know enough about what will happen in the market, so flexibility is very much part of the theme that we have to be providing. In other words, we have to allow the process to make it up as they go along.

Finally, we have to think about unbundling the process, because if we try to solve the problems of who is going to pay, if we try to solve the problem of how do we get a demand side bidding system on a level playing field with supply side options, if we try to make sure that the prices are going to be right and all the beneficiaries will in fact pay their true cost, we are never going to get started.

Instead, we have to focus on the utility as purchaser. We have to go out and find the utility taking bids from various sources and making the purchase of the right conservation choice in terms of what is least-cost, and we have to build a margin into their purchase, that is, something above the cost, so that they can come away with a return. That, to me, is the way to fix the regulatory process.

Attempts to change rate-based regulation through higher rates of return, or by expanding rate-based treatment of conservation, are probably good things, but to me they are not the ultimate solution because they are built upon a very weak foundation. A foundation, as I have just said, even in the National Association of Regulatory Utility Commissioners in increasing numbers are accepting must be changed because it is a fundamental failure in the process, because it rewards sales and not what people seem to want, which are energy services.

Thank you.

[The prepared statement of Dr. Cicchetti follows:]

Prepared Statement of

Charles J. Cicchetti, Ph.D.
Managing Director,
Putnam, Hayes & Bartlett, Inc.
and
Deputy Director,
Energy and Environmental Policy Center,
John F. Kennedy School of Government,
Harvard University

Before the

Committee on Energy and Natural Resources
of
The United States Senate

Related to

The Demand-Side Provisions of the
Public Utility Regulatory Policies Act of 1978 (PURPA)
Contained in Subtitle B of Title III of S-324
The Natural Energy Policy Act of 1989

November 7, 1989

Prepared Statement of
Dr. Charles J. Cicchetti
Deputy Director,
Energy and Environmental Center,
John F. Kennedy School of Government,
Harvard University
and
Managing Director,
Putnam, Hayes & Bartlett, Inc.

INTRODUCTION

I have been asked to discuss the conceptual, rather than the practical, aspects of utility conservation programs. This will be difficult for someone who served as chairman of the Public Service Commission of Wisconsin when, more than a decade ago, that state instituted least-cost utility planning and extensive utility conservation and rate design programs which were far more comprehensive than required by PURPA. I suspect I was given my assignment today because I am also an academic and a direct participant in the conceptual debate on utility conservation programs, a debate that has covered about a decade and a half.

The principal problem with utility conservation programs is that debate, not action, has been the dominant utility experience across the nation. I do not believe that the debate has been driven by people who simply reject the notion of utility-sponsored conservation. Instead, I have concluded that this debate has taken, and continues to take, place because of two conceptually respectable and mutually exclusive propositions:

1. The task of regulation is to get the prices right, step aside and let the market work.
2. The utility market is fraught with market failures and externalities which require a pro-active public policy response in the form of a comprehensive utility conservation program.

Analysts in the first camp generally make two points. First, we have known a great deal about the marginal cost of electricity and how to design tariffs based on this information for nearly two decades. Aside from giving it lip-service, most states have ignored this information. Before attempting to force conservation on customers who may not want to purchase the necessary products, regulators should address the basic problem of tariff design. Second, notwithstanding the failure to restructure tariffs to make them economically efficient, the growth rate of electricity consumption has declined significantly from its historic norm of 7 percent per year (or a doubling of consumption every decade) because of the general increase in utility prices during the past decade.

Analysts in the second camp also generally make two points. First, the production and transmission of electricity is fraught with local and global environmental externalities ranging from the mine-mouth to the generating stations and the transmission grid. It is usually averred that having prices reflect direct utility costs might be a good first step. Nevertheless, direct utility costs do not begin to include the vast range of external costs.

Second, utilities can more efficiently provide customers with:

1. Information on what conservation products would work for them, and

2. Information on the costs and reliability of various conservation vendors. There are also differences related to social, utility and individual residential consumers' cost of capital, or discount rates. It is often alleged that failing to address these matters will lead to a vicious cycle of utility construction, rate shock, adverse environmental consequences and, ultimately, a consumer-driven political backlash which will make the late 1970s and early 1980s look like the good old days of utility tranquility.

I find myself agreeing with both points of view. I am not alone. And, therefore, the nation is trapped by debate and inaction. But, progress has been achieved. My role today is to explain four conceptual and public policy issues in the utility conservation debate. These issues are:

1. Participants versus Non-Participants
2. Least-Cost versus Least-Price Planning
3. Demand-Side Bidding
4. Incentive Regulation

I will take up each issue in turn.

1. Participants versus Non-Participants

The early phase of the utility conservation debate focused considerable attention on the fact that some advocates were urging utilities to purchase conservation products which were to be given freely to some customers (participants) and the costs spread over the bills of other customers (non-participants). This debate produced considerable interest in the so-called "no-losers test." Numerous papers and testimonies (some of my own included) were prepared to describe situations in which a neutral, or unknowing, regulator could not make a mistake because both participants and non-participants would have lower energy bills. Remembering this debate makes my head hurt. Recalling its subtleties gives me a migraine.

The good news for this committee is that this issue does not need to be revisited. There are two reasons for this happy fact. One is based upon a correct resolution of the conceptual problem and the other is a mostly erroneous bit of reasoning.

Let me begin by suggesting that the problem embodied in the "no-losers test" was and remains quite real. Beneficiaries should pay in some proportion to their gains (bill savings). Many incorrectly assumed that when utilities were forced to market conservation, regulators would make two mistakes:

1. Require conservation to be given freely, and
2. Pay too little or no attention to how the utility would collect the money to pay for conservation.

Recent evidence suggests that regulators know that they must concern themselves with who pays and who benefits as well as with the costs of various supply and conservation options. Regulators are, for the most part, not brain dead or ignorant of their responsibilities. To be sure, their approach might be to mix fairness, efficiency and political reality. However, I do not need to suggest to this committee that such a balancing of objectives is not a failure of regulation.

The erroneous basis for rejecting a rigid "no-losers test" public policy is the presumption that least-cost utility planning always means lower prices and negates any regulatory concern with the distinction between participants and non-participants. This simply is not so. Least-cost planning does not always yield a "win-win" result. Nevertheless, reasonable regulatory attention to cost recovery, rate design, program definition and utility incentives now make the "no-losers test" obstacle a thing of the past. And the public policy debate can and has moved forward.

2. Least-Cost versus Least-Price Planning

When I try to explain the distinction between least-cost and least-price planning, I often find myself returning to a final examination question I used to test my students at the Kennedy School of Government.

In my examination question, the students were told that a state required 1000 MW of power. The initial price of electricity is 5.95 cents per kWh. New supply-side options include: (1) a new generation station at a capital cost of nearly $2 billion and 3.95 cents per kWh for operating costs; and (2) ten independent power producers willing to sell the same quantity of electricity at 5.95 cents per kWh. In both circumstances, the price after expansion equals 5.95 cents per kWh.

Initially, the conservation option costs considerably less: $1 billion to save 1000 MWs, and no operating cost. However, the reduced sales mean that retail prices must increase to 6.15 cents per kWh. The student was asked to explain to the governor, who took credit for the more than $1 billion cost saving, why the utility now needs a rate increase. In that exercise, the A-student would have realized two things. First, when a supply option (e.g., a new power plant) is "least-cost," the utility acquires a new investment which can be used to generate electricity. The utility will collect additional revenue from the increased sales of electricity which were the forecasted reason for the new investment. However, when a conservation investment is the "least-cost" option, the utility must either raise revenue by charging customers for conservation, by raising the price of electricity or by some combination of the two.

The second thing the A-student would have realized is that the higher average electricity prices resulting from the conservation program are offset by reduced quantities of electricity consumed. Customer bills are calculated by multiplying price times quantity. Because some bills are reduced, regulators have sufficient room to determine who pays and who benefits in the least-cost context, regardless of the higher average electricity price.

3. Demand-Side Bidding

The focus of the more recent phase of the utility conservation debate is whether demand-side programs should be allowed to participate against independent power projects in utility bidding programs. There are two aspects of this debate. (1) Will the regulators get it right, or simply prefer conservation? (2) What price should a utility pay for conservation?

To the economist, the principal objective of public policy is unambiguous--economic efficiency. And to achieve the socially efficient outcome, the marginal cost of conservation (MC_c) is equated to the marginal cost of electricity (MC_e), sometimes called avoided cost. Presumably, there would be some under-investment in conservation when $MC_c < MC_e$. This would likely occur when the price of electricity (P_e) is less than its avoided cost (MC_e).

Consider the following example:

$$P_e = \$.08,\ MC_c = \$.05, \text{ and } MC_e = \$.10$$

Conservation should be substituted for electricity because MC_c is less than both P_e and MC_e. However, if $P_e < MC_e$ and consumers substitute conservation for electricity, they would stop too soon because P_e is not the economically efficient price, i.e., it does not equal the marginal cost of electricity.

In a recent policy debate, which is discussed in a paper by Cicchetti-Hogan, we advance a bidding proposal and what we call the Ruff-Joskow approach. Both would promote economic efficiency by addressing the problem of under-investment in conservation. We also discuss the Amory Lovins approach, which we concluded would over-correct the situation and, therefore, yield too much investment in conservation unless regulators intervene to prevent excessive conservation purchases. Under Cicchetti-Hogan, each bidder is required to pay the retail electricity price for energy services now provided by conservation instead of generation. Under Ruff-Joskow, when $MC_e > P_e$, they would condone the payment of a subsidy equal to this difference to promote the efficient outcome. Under a Lovins approach, unless restructured by regulators, the conserver would effectively be paid twice: once in the form of an avoided cost payment, and again by not having to pay the retail price for the electricity conserved. The unrestricted

Lovins approach is rather like paying a self-generator, who keeps the electricity for his/her own use, the same amount as would be paid to a cogenerator, who supplied electricity to the utility for resale.

Consider each proposal from a benefits/cost standpoint of customers.

Benefits – Costs for Customers

1. Cicchetti-Hogan

Benefits Costs

$$MC_e - MC_c = \$.10 - .05 = \$.05$$

2. Ruff-Joskow

Benefits Costs

$$P_e + (MC_e - P_e) - MC_c = \$.10 - .05 = \$.05$$

3. Lovins

Benefits Costs

$$MC_e + P_e - MC_c = \$.10 + .08 - .05 = \$.13$$

The first two approaches are based upon the proposition that economic efficiency is achieved when the marginal cost of electricity is equated to the marginal cost of conservation. These proposals would achieve this objective by eliminating the influence of the electricity price from consideration when it is less than the marginal cost of electricity.

When price exceeds the marginal cost of electricity, the incentive to conserve is greater than under any system based upon a lesser avoided cost payment (unless the conserver is effectively paid twice). Under the Cicchetti-Hogan approach, consumers would participate, if the value of the information embodied in the utility program exceeded the difference between price and avoided cost. Under the Ruff-Joskow approach, while neither has recommended such a policy, would both for symmetry and economic efficiency require a tax, or negative subsidy of (P - MC$_e$), on utility conservation.

To understand how each approach might work, continue to assume the same prices and costs as above, that monthly consumption is 1,000 kWh's, and a conservation bid is for 100 kWh's. The customer's bill before conservation would be $80.00 per month.

Without a utility conservation program of any kind, the conserver would not receive the correct incentive. The customer would pay $72.00 for electricity and $5.00 for conservation, or $77.00 per month. Under the Cicchetti-Hogan plan, the customer continues to pay $80.00 per month to the utility, but this is broken down into $.08 (900 kWh) + $.08 (100 energy service units). However, if the customer bids 100 kWh's of saving at a cost of $5.00 ($.05 x 100 kWh) and receives a payment of $10.00 ($.10 x 100 kWh), he/she pockets $5.00 per month, and thinks his/her energy costs have been reduced to $75.00 per month.

Note that under Ruff-Joskow, we get the same result. The customer now pays $72.00 for electricity, receives a $2.00 subsidy for conservation, but must spend $5.00 for conservation. This, of course, also adds up to $75.00 per month for energy.

Finally, under Lovins, the customer pays $72.00 for electricity, receives a payment of $10.00 for conservation and spends $5.00 for conservation. The end result -- unless, as I have sometimes heard Lovins suggest, this is either prevented from happening or is fixed through tariff adjustments by regulators -- would be a net cost to the customer of $67.00 per month for energy. To be sure, it is my conclusion that regulators would indeed by urged to repair such overpayments both because it would be economically inefficient and because regulators do not like rate increases.

Economic efficiency requires the choice between conservation and consumption to be based upon their respective marginal costs. Corrective action is required when utility prices do not provide the right information for this choice. Unless based upon external cost considerations, utility-sponsored conservation programs should be designed to equate the marginal cost of conservation to the marginal cost of electricity supply. Otherwise, the conservation option will be treated neither neutrally nor efficiently. Bidding demand-side options can achieve economic efficiency, if regulators define the products bought and sold as energy services. The conceptual resolution of this debate has permitted regulators to turn to more practical implementation issues.

4. Incentive Regulation

A friend of mine, John Rowe, CEO of a very progressive electric utility, New England Electric System Companies, compared a utility CEO to a rat smelling cheese. His conclusion was that you can train the rat to do a lot of things, but if you want to watch the rat perform vociferously, give the rat both the scent and the prospect of a hearty meal of cheese.

There is not much debate concerning the proposition that electric utilities are businesses which will respond to economic incentives. Some would argue that no one should profit from conservation and that regulators have sufficient financial power in the form of negative actions to force utilities to do whatever the regulators want them to do. Maybe so, but increasingly, regulators are accepting John Rowe's proposition that a little cheese goes a lot further in making a rat perform than a "kick in the butt" or an "electric shock."

The debate, and it really is incorrect to classify this issue as such, is related to the range of affirmative incentives being reviewed in the various states.

Five steps are typically involved.

- *Set a conservation objective.* This might be in terms of the number of buildings to be weatherized, kWs or kWhs to be "saved" or any other objective that seems plausible and achievable.
- *Specify the source and amount of resources to be expended.* This can be done by setting specific sums to be spent, or establishing a system of incentives that will call forth those resources.
- *Establish the rules of the game.* The utility must know how the costs of the program are to be allocated, how rates are to be set and how energy services are to be priced.

- *Establish a plan for evaluating the program.* This should include criteria to be used in such an evaluation, data to be gathered and a target date for the evaluation.
- *Modify the plan as necessary.*

It is important to specify the principles that will define the course of future policy and planning. For example, if a state wants to treat conservation like reliability and have all consumers pay for it, this should be decided before plans are made and evaluated, and not as an option along with many to be decided in conjunction with the planning process. Similarly, if shared-savings or marketing energy services are to be used by the utility to market conservation, the incentives and ratemaking principles, which will define such a policy, should be established prior to the planning process.

Some proposals attempt to achieve the results that regulators guess would be achieved were energy markets more perfectly competitive. Other plans set goals different from those that markets would produce. That is a policy choice for regulators and legislators, and one they have made in favor of non-market objectives in the past when subsidizing consumption of low income groups, or residential as opposed to commercial customers, or (by eschewing marginal cost pricing) on-peak users.

Where non-market goals are to be incorporated into the regulatory approach, they should, ideally, be both explicit and transparent, i.e., their cost should be known and clear, so that these goals can be achieved at the lowest possible cost.

The market approach to utility conservation policy begins from a different vantage point. Rather than establishing goals, it seeks to get utility and consumer incentives right, and let the results fall where they may. Few regulators I know are willing to let markets decide, either because they hesitate to give up control of the conservation-consumption trade-off, or because they fear that markets are so imperfect that the results that are relying on them will be sub-optimal. But, fewer regulators still are willing to adopt overtly anti-market approaches in an era in which competition and deregulation hold the high moral and intellectual ground.

The general resolution of conflicting concepts has been to tinker -- to retreat from "command-and-control" programs to programs that rely on utilities to respond rationally to a set of regulator-determined incentives. This is a kind of melding of regulation and enterprise: Regulators set the incentives, and utilities respond in the most efficient ways they can devise. It is in this spirit that the NARUC Conservation Committee recently identified six reforms that are intended to utilize incentives to modify more traditional regulatory practices. These are listed in Table 1. (Appendix A describes each in greater detail.)

Table 1

SOME RECENT INCENTIVE REGULATION OPTIONS OF THE NARUC CONSERVATION COMMITTEE

1. "California" Volume of Sales (ERAM) Adjustment
2. Higher Rate of Return on Conservation Investments
3. Shared Savings Between Customers and Shareholders
4. A General Regulatory Contract to Perform
5. Specific Bounty Based Upon Contract Performance
6. Comparative Bill Earnings Adjustment

Each incentive represents a system to reward, or at least not to penalize, utilities which aggressively pursue energy-efficiency-enhancing objectives. Based upon these specific NARUC proposals, a more generalized framework for reforming traditional rate base regulation to reflect positive incentives is shown in Table 2, which summarizes two general mechanisms for incorporating incentives into a traditional regulatory framework. The first is an adjustment for the utility that stands ahead or behind the "pack." This can be either explicit or implicit. If the latter, the regulator must go to some lengths to "communicate" its differential treatment. Either the rate of return (ROR) or revenue requirement (RR) can be altered under this approach to incentive regulation.

The second adjustment mechanism is based upon specific performance indices. A variety of modifications to the traditional regulatory formula might be used to provide incentives which can be quite specific (e.g., use per customer), or somewhat more general (e.g., overall performance).

Table 2

MECHANISMS FOR USING ECONOMIC INCENTIVES TO ENCOURAGE EFFICIENCY UNDER COST-OF-SERVICE REGULATION

- Recognize a Job Well (or Poorly) Done by Either an Implicit or Explicit Ex-Post Adjustment to Earnings
    1. Base the ROR on a Subjective Determination of Performance
    2. Add (Subtract) $X to (From) the Revenue Requirement (RR) as a Bonus (Penalty)
- Make Specific Adjustments to the Traditional Cost-of-Service Formula
    1. Provide for a Higher ROR for Specific Efficient-Enhancing Investments
    2. Adjust ROR, $Y of RR, or Average Prices Based on Specific Performance Criteria, Such as Changes in Predicted:
        - Sales Volumes
        - Use Per Customer
        - Peak Demand
        - Typical Customer Bills (Price Times Quantity)

An alternative approach is to abandon rate base regulation entirely and to establish a system in which the utility profits when it selects the least-cost demand- or supply-side choices. This approach is a special sub-category of a more comprehensive form of price cap regulation. For example, one approach to encourage conservation could be initiated by first determining avoided cost (market-derived bidding schemes are preferred to administratively-determined avoided costs schemes). When a utility supplier saves kWs or kWhs or generates the same from new sources, it might be paid a fixed percent of the avoided cost standard. A contract between regulators and the utility would replace traditional rate base cost-of-service regulation. The incentive would not be based upon the utility's cost, but on the value of alternative sources of supply. Many decisions concerning risk, contract re-openers, reporting, etc. would need to be made by the various parties. Regulatory, financial and political considerations would necessarily shape the evolution of any such policy direction.

CONCLUSION

My conclusion is that the time for debate has ended. Now, regulators must engage in deliberations concerning how to introduce utility conservation programs into the marketplace.

My preference is to focus attention on the utility as the purchaser of demand-side programs. These will be resold to customers for a profit based upon the difference between the price paid for the conservation and avoided cost, perhaps even including external costs.

Utilities should be given a profit incentive for their successes and suffer losses for their failures. Programs should be flexible and modified as necessary.

Customers should pay when they benefit. Monitoring performance, encouraging R&D and marketing should be embodied in the plans. Finally, it is important to accommodate both the low cost conservation, as well as options, which might be more costly but still be less expensive than avoided cost. This committee's next panel will discuss the specifics of a Conservation Law Foundation and New England Electric System's collaborative project, which embodies much of what I have recommended to you. Understanding that I have advised both groups, I very much recommend this program as an important, practical, yet still quite visionary, first step. Policies to encourage utility conservation and incentive regulatory reform do not lack creative and innovative ideas. Implementation, while promising, is still lacking. Any support and encouragement that this committee can give will yield significant benefits for the nation's economy and environment.

Appendix A

SOME RECENT INCENTIVE REGULATION OPTIONS OF THE NARUC CONSERVATION COMMITTEE

1. California regulators have adjusted retail prices in recent years when there has been variation between the level of sales forecasted in a rate case and actual sales.

The principal reason behind this program, known as ERAM, was to adjust for the year-to-year variation in weather and the fluctuating availability of hydroelectric capability, although, perhaps unintentionally, such an adjustment mechanism also increases retail prices if conservation increases, and reduces them if conservation fails to materialize.

Conservation advocates sometimes refer to "the front-page test." This means that any program must be evaluated in light of the possible reaction of the average reader of a local newspaper. If the conservation savings projected by a regulatory commission failed to materialize, an ERAM-type mechanism would mean that utility prices would be reduced. Such an outcome would most likely pass the front-page test, especially if the initial increase in prices to accommodate the conservation forecast had been described somewhere on the back page. But, it is unclear whether customers will react negatively to the unit price increases their conservation would trigger, or positively to the decline in their total bill. Politicians, not noted for bravery in the face of consumer ire, are likely to fear the worst – an outcry at rising unit prices.

This is unfortunate, since a volume of sales adjustment would at least provide some incentives for a utility to promote conservation. However, such a program is not without some shortcomings. First, other factors, e.g., weather, which have nothing to do with the success or failure of any utility-sponsored program, would also affect retail prices and utility earnings. Second, the mechanism does nothing to encourage the least-cost choice between generation, conservation and third-party suppliers. Accordingly, unless complemented or expanded by regulation or markets, the ERAM mechanism is but a crude and partial adjustment to accommodate conservation.

2. Some states have considered the adoption of a conservation/incentive program similar to that of the Public Service Commission of Wisconsin's plan. Such programs are not market-oriented, but are typically put forward out of frustration that the market needs coaxing. These programs are rather straightforward extensions of traditional ratebase regulation. To encourage conservation, a regulatory commission could increase a utility's earning on politically or socially desirable investments, e.g., conservation and efficiency improvements.

The adjustment mechanism could be obvious; for example, regulators could grant a higher authorized rate of return for investment in conservation than in generation or transmission. Regulators might also approve more generous amortization schedules for conservation investments. A related approach would permit a utility to pass conservation costs as incurred directly on to all customers, while providing for some recovery of revenue which exceeds the cost of conservation.

Because such programs are based upon traditional regulation, they typically invite standard options for customers which may not be least-cost. Measuring performance, making up lost revenue and predicting consumer response continue to be difficult and often invite regulatory meddling, or, for others, fine-tuning. Such an approach is likely when traditional regulation is embraced, conservation preferred and incentives found to be useful.

3. Shared savings programs have two characteristics. First, the utility segregates its business into two components. Usually, one is regulated in a traditional cost-of-service sense. Second, the success or failure of the other component of the business is shared between the customers of the regulated entity and the shareholders.

One recent example of this concept is an order by the New Jersey Board of Public Utilities for Elizabethtown Gas Company.[1] The company's natural gas distribution business was divided into a competitive industrial sales entity and a regulated cost-of-service company. However, a portion of the net income of the competitive industrial sales component was shared between the regulated customers and the shareholders.

The most significant feature of this program was that, in the first instance, residential prices were increased to absorb the fixed charges and previous contribution to earnings derived from the previously regulated industrial sales.

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[1] State of New Jersey Department of Energy, Board of Public Utilities, Docket No. GT 8602131, September 1986.

Offsetting this residential price increase was the fact that the future returns from the expanded competitive industrial sales entity were shared between the regulated customers and shareholders. The logic of this payment to residential customers was that this was a return for accepting the risk of recovery and responsibility for the earnings previously contributed by the industrial customers.

This general approach can be applied to conservation. A utility would diversify into a conservation business and cost savings and earnings would be allocated by regulatory decisions between the regulated customers and the shareholders in the diversified energy services company. Two problems are rather obvious. Other suppliers of conservation might find that such an arrangement puts them at an unfair competitive disadvantage. Second, the program is based upon a system of cross-subsidies, which could become a regulatory quagmire.

4. Performance contracts have been used in a number of French-speaking nations to regulate the performance of government-owned entities. The process is conceptually simple. The government (i.e., the owner) determines a limited number of very specific objectives that it expects managers of a particular utility to achieve. These are described in formal performance contracts.

The principal feature of the program is that it defines what management is expected to achieve. But incentives, if they are involved, are implicit. Good performance means promotion or less meddling by government. Bad performance means disgrace, discharge, etc.

5. Bounties based upon performance contracts are an obvious modification, which would make the incentives under a performance contract explicit. The

incentives could be in the form of increases in rates of return allowed on rate base, an expanded concept of rate base or a simple addition to net income collected by increasing prices. The Mississippi Public Service Commission approved such a performance contract bonus program in which seven objectives and corresponding weights were utilized to adjust the allowed return on rate base without formal rate case.[2]

6. The state of Maine has recently been investigating how to implement a program that would adjust earnings based upon the performance of a utility as measured by comparing a particular utility's typical bill with an index composed of bills of other utilities. The purpose is to provide incentives: (1) to reduce the cost-of-service by encouraging a utility to select the least-cost option, whether it means IPPs, purchased power conservation or generation; and (2) to promote less electricity consumption by encouraging conservation or substitutes.

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[2] Mississippi Public Service Commission Order, Docket No. U4761, August 7, 1986.

Senator **Ford** [presiding]. Senator Wirth had to leave, and he apologizes, but he will be back.

Cheryl Harrington, we are delighted to see you here, you improve the panel considerably. And we will let you proceed at this time.

We will accept your total statement for the record. If you would highlight it, we would appreciate it, in 7 minutes.

STATEMENT OF CHERYL HARRINGTON, COMMISSIONER, MAINE PUBLIC UTILITY COMMISSION, ON BEHALF OF THE NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS

Ms. **Harrington**. Thank you.

I am Cheryl Harrington, Commissioner for the State of Maine, where I have served as the Public Utility Commissioner since 1982, which is the year that Maine first got serious about implementing the PURPA standards that exist in the law right now.

I am here today representing the National Association of Regulatory Utility Commissioners, and specifically the National Association's Energy Conservation Committee.

NARUC, the National Association, has strongly endorsed the generation planning strategy known as least-cost planning, which integrates both supply- and demand-side resources to meet future utility load requirements.

And NARUC has further, specifically endorsed least-cost planning as an important element in the strategy to reduce the threat of global warming.

As to the two PURPA amendments that are under discussion today, the National Association does not have a policy position for the reason that we act by resolution of the entire body, and this body has not yet met to consider these two amendments.

However the Energy Conservation Committee has considered these two amendments, and there is strong consensus within the committee supporting them both.

Now let me speak to them one at a time.

First, the requirement that the states each consider the least-cost planning strategy, and specifically when considering that strategy, consider the issue of profitability for conservation investments and the incorporation of environmental cost.

These are things that really do need to be done by federal legislation. The reason is that least-cost planning, even though it has been around as a theory and strategy for four years, has yet to be undertaken seriously only in but 10 states. Almost half of the states have looked at it to some degree, but only 10 states, after four or five years, are actually practicing least-cost planning.

On the other hand, 25 states have not even considered least-cost planning. So there is really a long way to go in the learning about and the implementation of this generation planning strategy.

Also, even in the 10 states that are actively practicing least-cost planning today, only two have seriously taken up or acted on the issue of profitability, which is, how does one make demand-side investments, conservation investments, as profitable for a utility as supply-side investments?

Two states have acted, and there are about four, perhaps five states, that are about ready to consider whether or not they want to act on the issue. But again, that is far short of even a majority of the states looking at this serious impediment to demand-side investment.

Also, on the incorporation of environmental cost, when one does the comparison between various resources to decide which is the least cost and which resource ought to be implemented before another resource, the weighing in of environmental cost is also only done, so far, by two states, by Wisconsin, and recently by the State of New York. None of the other states have moved on this issue of incorporation with environmental cost.

So that these PURPA amendments, which would require the states to take a look at least-cost planning, take a look at the issue of profitability for conservation, and take a look at the issue of incorporating environmental cost, and to require the states to report back in two years as to what they have found, what they have done, or why they have not implemented these strategies, can really be expected to push the country forward in looking seriously at the energy efficiency resource, and in fact, getting it seriously underway in development.

The other major amendment to PURPA would require the purchase of qualifying conservation. I want to tell you briefly about Maine's experience in purchasing qualifying conservation.

But, lest my time run out before I make the even more important point, let me take the arguments of the critics, which is you cannot have them purchase a qualifying conservation because we do not yet know how to quantify the results conservation. We do not know how to measure whether or not we are getting the amount of kilowatt or kilowatt hour savings that programs propose to give us.

Another argument is the free rider effects. Why should utilities buy conservation from third parties for their customers, when in fact the customers may very well have put that conservation in for themselves, but they just wait for the utility to make the investment?

Another argument is that we really do not know how long these conservation measures are going to last. Not knowing how long they are going to last, how can we really compare them or buy them seriously from third party providers and compare them with our well-known supply-side resources?

And the fourth argument that one often hears is the rebound effect. Which is, you put in conservation for an industry or for a commercial building or for a residential home, and then all of a sudden, because the energy bill goes down, the family or the businesses decide to use more energy in another way, and the energy bill goes back up. This is known as the rebound or the kazoom effect.

Well, all of those arguments are in fact serious considerations when one is implementing demand-side and conservation measures, but they have nothing to do with the purchase of qualifying conservation from third parties, in that these problems exist when any utility does any conservation. And they have to be dealt with whether or not the utility is doing the conservation or whether they purchase it from third parties.

So really, these are valid considerations, but they are improperly relied upon as arguments against purchasing from third parties.

Now let me briefly tell you about the experience that we have had in Maine with the purchase of qualifying conservation. We have moved ahead without a federal statute, but, on the other hand, we have moved ahead on a lot of things in Maine, and I must say, ahead of several states, although we are trying to pull our sister states along.

In Maine, our largest investor-owned utility is already engaged in the practice of all-resource purchasing as required by this amendment to the PURPA Act.

The Central Maine Power Company, which pioneered the practice of competitive bidding for the purchase of supply-side PURPA resources, has now held two power purchase options, which invited demand- and supply-side bidders to participate and compete head-on with one another.

CNP first did the bidding in December of 1987, and it received 13 projects in response to their bid request, totalling 30 megawatts, which is one-half of CNP's annual load growth of about 60 megawatts.

Demand-side proposals all ranked in the top third of the bid proposals received, and CNP entered into active negotiations with seven of the proposals, totalling over 15 megawatts, and ultimately contracts were signed for six projects.

The projects were residential projects, commercial projects and industrial projects. And in each case the contract signed with the seller of the qualifying conservation specified that the payment would only be made for conservation achieved. In other words, if the conservation was not there, the utility would not pay the contractor or the third-party provider. So there was protection for the utility and for the rate-payer.

In a recent round of bidding, the second round, CNP again received bids for over 30 megawatts of conservation from nine projects. And although these bids have not yet been finally analyzed and acted upon, all the bids are still in the running with a total of 1,088 megawatts, which are still under consideration in this most recent round of bidding.

So, in each case, the conservation received by the utility was extremely competitive with the supply-side resources and, in fact, there is no indication that the resource is anywhere near depleted in the State of Maine.

And that fact is particularly interesting, because Central Maine Power is an extremely aggressive utility in its own implementation of demand-side programs. So we have a state in which the utility has been very active on conservation, and yet we have still seen the development of a conservation market through the purchase of qualifying conservation.

Thank you.

[The prepared statement of Ms. Harrington follows:]

UNITED STATES SENATE
COMMITTEE ON ENERGY AND NATURAL RESOURCES

TESTIMONY OF THE

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS
1102 INTERSTATE COMMERCE COMMISSION BUILDING
P.O. BOX 684, WASHINGTON, D.C.

PRESENTED BY
CHERYL HARRINGTON, COMMISSIONER
MAINE PUBLIC UTILITIES COMMISSION

ON

S. 324
GLOBAL WARMING AND ENERGY EFFICIENCY

NOVEMBER 7, 1989

1889

Summary of Statement of Commissioner Harrington for NARUC on Subtitle B of Title III of S. 324

NARUC has strongly endorsed the generation planning strategy known as least cost planning which integrates supply and demand side (energy efficiency) resources to meet future utility load requirements. NARUC has further specifically endorsed least cost planning as an important element in the strategy to reduce the threat of global warming.

The creation of a federal mandate that each state regulatory authority consider least cost planning will greatly assist the implementation of this planning strategy and can be expected to lead to greater use of the energy efficiency resource. It is important that a utility's least cost plan be it most profitable plan and that environmental costs be included in the least cost analysis. At present about half of states have taken some action on least cost planning but to date only ten of them are in fact practicing least cost planning. More action is needed.

The amendment of PURPA to require utility purchase of qualifying conservation will provide the capital needed to stimulate the growth of the energy efficiency industry much as has occurred with the qualifying facilities industry. It is a proper role for the federal government to foster investment in energy efficiency which is a vital component of an environmentally sound, least cost national energy policy.

The use of the nonparticipants test in Section 313(b) of Subtitle B should be dropped as it places undeserved and distorted importance upon a relatively small potential regulatory inequity and may very well discourage the development of cost effective energy efficiency. Further, the definition of "incremental cost" in this Section should be amended to include costs paid by participants if the full incremental cost is to be captured.

National Association of Regulatory Utility Commissioners
Testimony of Commissioner Cheryl Harrington
Maine Public Utilities Commission

A. Introduction.

I am Cheryl Harrington, Public Utilities Commissioner for the State of Maine, here today representing the National Association of Utility Regulatory Commissioners (NARUC) and its Committee on Energy Conservation. My comments address primarily Subtitle B of Title 311 of The National Energy Policy Act of 1989, S. 324, and should be read in conjunction with previous testimony given by Commissioner Stephen Wiel of Nevada on behalf of NARUC in broad support of S. 324.

B. State adoption of least cost planning.

NARUC has strongly endorsed least cost planning, a utility planning strategy which integrates both supply and demand side resources to fill anticipated energy services requirements. Further, NARUC has specifically endorsed least cost planning as an important element of our national strategy to reduce emissions and the potential for global warming. For these reasons we commend Section 311 of Subtitle B of Title III which would require each state regulatory authority to consider the implementation of LCUP on a basis which would, first: make a gas or electric utility's least cost plan its most profitable plan, and second: specifically include consideration of environmental costs in the formulation of the least cost plan.

Several states already require their utilities to do least cost planning. A recent survey conducted for the National Association of State Utility Consumer Advocates (NASUCA) found that ten states practice least cost planning, eight states have implemented it in law but not yet in practice, four states are developing least cost standards, and three states are considering it. On the other hand, fully one half of the states have not yet even begun to consider it. The Electric Power Research Institute (EPRI) ranks the number of states in which serious activity has occurred somewhat higher.

Those numbers are of course encouraging, but we have a long way to go. Moreover, few state regulatory authorities, including those who now practice least cost planning, have even taken up, much less solved, the issue of how to make the least cost plan the utility's most profitable plan. Fewer still have addressed the issue of how to incorporate environmental costs in a least cost plan, particularly those environmental costs which are external to a project and would not ordinarily be considered a direct cost.

Because there is still so much to be done on the state level to include energy efficiency as a fully integrated power source, the section of S. 324 which requires each state to consider all aspects of least cost planning and report back to the Federal government within two years can be expected to result in a real step forward in the nation's energy planning, and specifically in the increased use of the energy efficiency resource.

C. Utility purchase of qualifying conservation.

NARUC also supports amending the PURPA portion of the Federal Power Act to require utility purchases of qualifying conservation (Sections 312 and 313).

Requiring utilities to purchase conservation from third-party vendors can be expected to create a viable and substantial conservation industry just as the development of a strong third party market for qualifying supply side facilities has already occurred under the existing PURPA law. This amendment will create a powerful tool to overcome the strong resistance many if not most utilities now exhibit towards investing in energy efficiency.

In the case of qualifying facilities, Congress was aware that the cogeneration and small power facilities were an available but under used resource that the utilities were refusing to buy, or refusing to pay a fair price. With the passage of PURPA in 1978 and the implementation of its power purchase requirements in years subsequent, we have seen a dramatic shift in utilities' practices with regard to such purchases, and nowhere has this been greater than in the Northeast.

The requirement that utilities purchase qualifying conservation will provide the still nascent conservation industry with the capital it needs to grow into a fully-fledged industry which can contribute to the development of the vast untapped and very low cost energy efficiency resource for the American economy. Increased efficiency can provide this nation with much of the energy we need to support our expanding economy, and can do so at a lower cost than conventional sources. Perhaps most importantly, it can do it while improving our global environment. As a matter of national policy, we can no longer forego the benefit of increased energy efficiency. This increased efficiency, I believe, will be greatly stimulated as the result of requiring the purchase of qualifying conservation under PURPA.

In Maine, our largest investor owned electric utility is already engaged in the practice of all-resource purchasing as would be required by this bill. Central Maine Power Company, which pioneered the practice of competitive bidding for the purchase of PURPA supply side resources, has now held two power purchase auctions which invited demand and supply side bidders to participate and compete head-on with one another.

CMP issued its first all source request for proposals on December 4, 1987. Thirteen projects totaling about 30 MW (half of CMP's annual load growth) were proposed. The demand side proposals all ranked in the top third of the proposals received. CMP entered into active negotiations on seven of the proposals totaling over 15 MW, and ultimately, contracts were signed for six projects. They included industrial, commercial and residential programs. The vendors ranged from industrial firms doing their own conservation projects to third-party vendors implementing conservation projects for others. Each project was carefully negotiated with an emphasis on cost-effectiveness and to ensure that the project could be appropriately monitored and evaluated.

In one of these projects, an energy service company is treating more than 10,000 homes with insulation, super efficient lighting, water heating improvements, sealing of cold air drafts and other weatherization measures. Over the life of these measures, the total electric bill for each treated home will average about $2,500 less than in an untreated house. And let me emphasize that the utility pays for this work only to the extent that metered savings actually occur. If the energy service company doesn't deliver, it doesn't get paid.

Another small company has contracted with CMP to market lighting efficiency and other retrofits to commercial and industrial customers. During the next five years this contract should save an estimated 48 million kilowatt-hours a year and 9.5 megawatts of capacity. CMP will monitor each project's effectiveness and pay for kilowatt-hour savings as they occur. And in a series of contracts with large commercial, industrial and institutional customers, CMP is purchasing efficiency in diverse ways, from new lighting systems and redesigned machinery to improved industrial processes and new control systems for heating, ventilating and air conditioning. In every case, the contracts provide that the utility pays less by saving electricity than it would have to produce it.

In its most recent round of bidding, CMP received bids for 31 MW of conservation from 9 projects. All of these bids are still in the running within the total 1088 MW still under consideration. In each case, the conservation bids were among the lowest received by the utility and there is no reason to believe the resource is anywhere near depleted. This experience is particularly interesting in light of the fact that CMP has been an extremely aggressive developer of demand side investment.

D. Two problems within the proposed PURPA amendment.

There are, however, two problems with the proposed PURPA amendments. The first, which appears in Section 313(a), is the way the so-called "non-participants" test is characterized as an efficiency test. The non-participants test is not a test of economic efficiency at all. Rather, it is a consideration dealing with the equitable treatment of customers which falls out of the cost benefit test.

Any resource purchased for an amount no greater than the incremental cost of alternative energy (Alternative (A)) will benefit the aggregate of ratepayers and for that reason alone should be a candidate for purchase regardless of whether the particular conservation measure may benefit some ratepayers more than others. All ratepayers as a group are benefitted by acquiring the next resource at or below incremental cost. Such benefits include lower overall revenue requirements, reliability benefits, and reduced pressure on scarce transmission resources. Therefore, purchases at or below incremental cost should be eligible for consideration as qualifying conservation. While equity concerns may also be important factors in determining which programs to pursue, they should not be confused with efficiency issues.

The second proposed test (Alternative (B)) focuses on the benefits a particular customer may or not receive from the conservation investment does run ratepayer equity. Because energy efficiency results in a reduction of the number or potential number of kilowatts or kilowatt hours sold, the costs of energy efficiency investments are distributed over a fewer number of units, thereby increasing the price of each unit. For those who are consuming fewer units as a result of the conservation measure, the increased cost per unit will be more than offset by the decreased demand. The non-participant concern is for those who cannot benefit directly from the offered conservation measure. Even though the system as a whole is benefitted, they face the increased cost per unit and will not experience a simultaneous decrease in demand. This is an inequity.

An example of the potential absurdity of using the non-participants test as a test of cost effectiveness rather than as an equitable consideration can be seen as follows. The non-participants test would dictate that the utility do no conservation, even conservation obtainable at zero cost, as any kwh saved would raise the price for non-participants. The utility should refuse a free energy resource! Further, it would be in the non-participating customer's interest to pay up to the difference between average cost and incremental cost to remove insulation from attics or to un-weather shield a house or business. That makes no policy sense at all. Non-participant impact is a consideration of equities, nothing more.

Ratemaking has many such equitable considerations and a large part of what state regulatory commissions do is make judgments for society about such potential or real inequities. However, as inequities go, this one, even at extravagantly expanded levels of investment in energy efficiency, is relatively small. An example of a more typical and much larger inequity is the allocation of the costs of cancelled or abandoned plant. Cancelled plant cost in Maine in the 1980's ran to more than $500 million. These were all non-productive sunk costs, which had to be allocated even though no economic efficiency goal was served. Such allocations, which occurred in many states, are essentially exercises in equity.

Similarly in ordinary rate design practice, costs are allocated to classes of customers, based upon the aggregate use characteristics of the class. They are not assigned according to individual use which would require an impossible minute by minute monitoring. My daughter who studies from midnight to 3 a.m. imposes significantly less cost on her serving utility than do I who use my lights from 4 until 10 p.m., yet in most jurisdictions both of us would pay exactly the same kwh rate. In total dollar amounts these basic rate design inequities are much larger than those presented by the distribution of conservation costs.

A second problem in this section of the bill is with the definition of "incremental cost." (Section 313(c)). This definition

> "incremental cost of alternative electric energy means, with respect to purchases of qualifying conservation from qualifying conservation entities, the cost to the purchasing electric utility of the electric energy which, but for the purchase from such conservation entity, such utility would generate or purchase from another source"

looks only to the utility's cost and thereby fails to capture the full incremental costs. In many cases some portion of the costs of a conservation program are picked up by the participants in the program. It is the total of the utility's cost plus the participants' cost for the conservation resource which represents the real incremental cost of that resource. In fact, by shifting some portion of the costs to participants, a utility can mitigate the effects upon non-participants discussed earlier. While it is well established that customers under value conservation investments as compared to their other purchases. A utility need not always pay the entire cost of each conservation measure in order to get the customer to participate. Utilities should indeed be encouraged to develop those cost effective programs in which some portion of the cost is paid by the participating customer.

This concludes the prepared comments of NARUC in regard to Subtitle B of Title 311 of S. 324. We stand ready to provide additional information as the Committee may request.

Attachments

1.NARUC Resolutions on Global Warming (2)

2.NARUC Resolution in Support of Incentives for Electric Least-Cost Planning

3.NARUC White Paper on Least Cost Planning and Utility Earnings

Resolution on Global Warming

WHEREAS, Recent scientific reports have provided new evidence that increasing concentrations of carbon dioxide in the atmosphere is causing changes in the world's climate patterns, including the potential for severe global warming (the "greenhouse effect"); and

WHEREAS, Emissions of carbon compounds, mainly from the combustion of fossil fuels, are a major contributor to the phenomenon of global warming; and

WHEREAS, Failure to take actions to reverse the trend toward global warming could bring economic, environmental and human disaster previously unimagined; and

WHEREAS, Improvements in energy efficiency offer a low-cost approach to reducing emissions of carbon compounds in the United States without sacrificing health and safety goals; now, therefore, be it

RESOLVED, That the National Association of Regulatory Utility Commissioners (NARUC), assembled in its 100th Annual Convention in San Francisco, California, calls upon the Congress and the President of the United States to swiftly enact legislation designed to improve the efficiency of the nation's use of its energy resources and reduce emissions of the nation's carbon compounds and to assist other nations in doing the same; and be it further

RESOLVED, That such legislation should be based on a least-cost approach, whereby the lowest cost options for reducing emissions of carbon compounds are implemented first; and be it further

RESOLVED, That Congress and the Administration should dramatically increase funding for research and development (R&D) and implementation of energy efficiency and renewable energy resources and henceforth should establish federal energy R&D programs and priorities which reflect the cost-effectiveness of various energy technologies in meeting future energy needs; and be it further

RESOLVED, That such legislation should take into account, and be consistent with, any legislation seeking to address the problem of acid rain, to assure integration of these environmental efforts.

Sponsored by the Committee on Energy Conservation
Adopted November 2, 1988

Resolution on a National Energy Policy Regarding Global Warming

WHEREAS, There is no scientific agreement as to whether global warming has yet begun and as to what pace such a warming would take; and

WHEREAS, The failure to take actions to reverse the trend toward global warming could bring economic, environmental and human disaster previously unimagined; and

WHEREAS, The public interest demands a coordination of scientific research efforts among governments, universities, research institutes, and nongovernmental organizations to improve the understanding of the world's climate patterns and the phenomenon of global warming and the greenhouse effect; and

WHEREAS, Congress has been considering legislation to coordinate efforts of the Federal agencies and other nongovernment bodies in establishing such a national policy developing and implementing energy research priorities; now, therefore, be it

RESOLVED, That the Executive Committee of the National Association of Regulatory Utility Commissioners, assembled at its 1989 Winter Meeting in Washington, D.C., urges that legislative proposals considered by Congress give adequate consideration to the need to include the interests and expertise of the States in ensuring a fully coordinated, national policy establishing energy research priorities; and be it further

RESOLVED, That the Executive Committee of the NARUC supports a national policy on global warming that is consistent with efforts to develop alternative energy sources and more efficient use of energy through conservation; and be it further

RESOLVED, That the Executive Committee of the NARUC respectfully requests the cooperation of the Federal agencies in seeking the passage of such legislation.

Sponsored by the Committee on Electricity
Adopted March 1, 1989

Resolution in Support of Incentives for Electric Utility Least-Cost Planning

WHEREAS, National and international economic and environmental conditions, long-term energy trends, regulatory policy, and technological innovations have intensified global interest in the environmentally benign sources and uses of energy; and

WHEREAS, The business strategy of many electric utilities has extended to advance efficiency of electricity end-use and to manage electric demand; and

WHEREAS, Long-range planning has demonstrated that utility acquisition of end-use efficiency, renewable resources, and cogeneration is often more responsible economically and environmentally than traditional generation expansion; and

WHEREAS, Improvements in end-use efficiency generally reduce incremental energy sales; and

WHEREAS, The ratemaking formulas used by most State commissions cause reductions in utility earnings and otherwise may discourage utilities from helping their customers to improve end-use efficiency; and

WHEREAS, Reduced earnings to utilities from relying more upon demand-side resources is a serious impediment to the implementation of least-cost planning and to the achievement of a more energy-efficient society; and

WHEREAS, Improvements in the energy efficiency of our society would result in lower utility bills, reduced carbon dioxide emissions, reduced acid rain, reduced oil imports leading to improved energy security and a lower trade deficit, and lower business costs leading to improved international competitiveness; and

WHEREAS, Impediments to least-cost strategies frustrate efforts to provide low-cost energy services for consumers and to protect the environment; and

WHEREAS, Ratemaking practices should align utilities pursuit of profits with least-cost planning; and

WHEREAS, Ratemaking practices exist which align utility practices with least-cost planning; now, therefore, be it

RESOLVED, That the Executive Committee of the National Association of Regulatory Utility Commissioners (NARUC), assembled in its 1989 Summer Committee Meeting in San Francisco, California, urges its member State commissions to:

1) consider the loss of earnings potential connected with the use of demand-side resources; and

2) adopt appropriate ratemaking mechanisms to encourage utilities to help their customers improve end-use efficiency cost-effectively; and

3) otherwise ensure that the successful implementation of a utility's least-cost plan is its most profitable course of action.

Sponsored by the Committee on Energy Conservation
Adopted July 27, 1989

PROFITS & PROGRESS

THROUGH LEAST-COST PLANNING

DAVID MOSKOVITZ
Energy and Regulatory Consultant
Hollywood Boulevard
Alna, Maine 04535
207-586-5838

Foreword by
John Rowe; President
New England Electric System

November, 1989

1889

National Association of
Regulatory Utility Commissioners
Room 1102 ICC Building; P.O. Box 684
Washington, D.C. 20044

Telephone No. (202) 898-2200

FOREWORD

By John Rowe
President & Chief Executive Officer
New England Electric System

In "Sir Gawain and the Loathly Lady," high king and chevalier must save no less than the peace of the kingdom and the pleasures of matrimony. While properly daunted by threats of at least greenhouse magnitude, they succeed, through painfully coming to understand that every woman wants her own way. In this white paper, NARUC transcends several sorts of chauvinism and applies similar wisdom to utility executives. That is none to soon, but wisdom is at least as remote on my side of the regulatory woods.

For most of our century, utility management has held to the faith that its product is fundamental to the social and economic well being of society, with positive externalities outweighing any possible negative ones. (This is provided, of course, that we can supply that product in our own way.) For several decades, a growing majority in NARUC has been building a new faith, now called least-cost planning, in which electric service is maintained (it is said) while growth in the consumption of electricity is radically curtailed through utility investment in customer energy efficiency. Meanwhile, the agnostic public (my customers - NARUC'S constituency) has voted for increased electricity supplies with its power switches and, increasingly, voted against such supplies with its ballots. No one is getting his or her own way.

Such discontent is hardly shocking. Public policies are not clear and the incentives to both consumers and producers are not consistent with the apparent trend of those policies (surprised anyone?). While environmental concerns jab at the consciences of commissioners, constrained electricity rates encourage the consumers to use more electricity. The utility is told to sell less of its chosen product and to provide a service it claims no unique ability to deliver. It must do this without being offered additional profit and often without being assured of cost recovery. Slowly, lashed by the misused slogan "duty to serve," utilities respond, but the overall results are credible to no one.

NARUC's 1988 policy statement - "a utility's least-cost plan for consumers should be its most profitable course of conduct" - provided fundamental recognition that the system of financial rewards must be made consistent with today's public policy objectives. This white paper provides a framework for achieving that consistency. Indeed, the words at the beginning of Section 2 should become a common creed for every commissioner and utility executive. Of course, I would quibble with details of this white paper, such as the suggestion that symmetrical treatment is an incentive instead of a minimum right, and the hint that suppressing utility profits is more important than the cost or quality of electric service. There is no time to quibble, however. The policies of the states my companies serve and the interests of those companies require that the theme of this report be implemented.

Successful proposals to implement the NARUC resolution should have the following hallmarks:

> They should be experimental. They should address most of the issues raised in this report, but should not purport to do so for all of the time.
>
> They should be modest. Success should provide retail companies with enough additional earnings to overcome the existing disincentives to the pursuit of energy efficiency.
>
> They should be direct. Utility managers must see immediate rewards.
>
> They should be powerful. Conservation, which for now appears the least-cost component of energy supply plans, must be the most profitable component.

I have had the privilege of leading two utilities with outstanding reputations for conservation efforts. But, neither has exhausted the conservation potential which commissioners and environmental groups believe exists. Incentive measures which are genuinely attractive to utilities provide the necessary means to develop the real potential, whatever it may be. Such incentive measures are equally necessary to obtain public credibility for least-cost planning.

ACKNOWLEDGEMENTS

I greatly appreciate the advice and assistance provided by so many people. To name just a few, Steve Weil, Cheryl Harrington, Joe Eto, Charles Goldman, Ralph Cavanagh, plus all of the usual suspects. Of course, thanks to DOE and the Conservation Committee and Subcommittee for the initiative to undertake this work and for the many useful comments and suggestions along the way.

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SUMMARY

In the broadest sense, this paper discusses issues relating to the earnings implications which flow from the pursuit of least-cost plans. More narrowly, however, the issues, discussion, and conclusions apply with equal force whenever a utility implements cost-effective demand-side measures, whether as part of a least-cost plan or not. To a lesser extent, the paper addresses how these issues relate to many supply-side options, particularly cogeneration and renewable resources.

Least-cost planning (LCP) is a process of examining all electricity-saving and electricity-producing options to select a mixture of options that minimizes total consumer cost, often including consideration of environmental concerns and other responsibilities.

Standing between LCP the idea, and LCP the practical reality, is the fact that the utility industry is responds rationally to its economic environment, a response which is strongly skewed against LCP. The same can be said of utility investment in energy efficiency; it is a clear public policy and regulatory goal, but it is not being pursued in an aggressive fashion. The reason is clear. Traditional regulation creates a strong economic disincentive to the utilities' implementation of least-cost plans or investment in energy efficiency programs. Indeed, the ratemaking process generally used in most states has the following unintended, but nevertheless perverse, incentives.

- *Each KWH a utility sells, no matter how much it costs to produce or how little it sells for, adds to earnings.*
- *Each KWH saved or replaced with an energy efficiency measure, no matter how little the efficiency measure costs, reduces utility profits.*
- *The only direct financial aspect of regulation that encourages utilities to pursue cost effective conservation opportunities is the risk that if they fail to satisfy regulators costs may be disallowed.*
- *No matter how cost effective, purchases of power from cogeneration, renewable resources, or other non-utility sources add nothing to utility profits.*

The incentives and disincentives created by traditional regulation flow from the interaction of accounting conventions, legal and procedural matters such as regulatory lag and retroactive ratemaking, and more recent additions to regulation such as fuel adjustment clauses. Whatever the cause, the incentives embedded in the current system of regulation present a serious obstacle to the successful implementation of least-cost planning (LCP).

In a Resolution approved in July, 1989, NARUC concluded that regulatory reform was needed to remove the disincentives to LCP and to make the successful implementation of a utility's least cost-plan its most profitable course of action. (See appendix C for the text of the Resolution.) It follows, therefore, that the single, overarching standard against which proposed incentive plans should be measured lies in the answer to this question:

> *Viewed from the perspective of the utility, what course of action would be consistent with a profit-maximizing strategy?*

Identifying a profit-maximizing strategy is the most important test of any incentive proposal, but other considerations are also quite important and should be given serious attention while developing or selecting the best plan for each state. These considerations, in general order of importance, are as follows:

Decoupling profits from sales;
Cost minimization;
Administrative simplicity;
Fuel switching;
Balance;
Predictability;
Environmental costs;
Non-participant impacts;
Skimming the cream;
Avoiding gaming; and
Distribution of incentives.

Incentive proposals have been grouped into three general categories based on the approach taken. The categories are:

Rate-of-Return Adjustments,
Shared Savings, and
Bounty.

For each of the approaches, sets of performance criteria are available to address one or more special concerns. All possible modifications to each approach have not been described. For the most part, regulators may mix and match different components of incentive plans until a desirable group of features is found.

To produce a reasonable profit-maximizing strategy, it will be necessary to decouple profits from sales. Under current regulation, increased sales always mean increased profits. As long as every incremental KWH sold adds to profits, the strong likelihood remains that a profit-maximizing strategy will lead to more sales and less DSM, even if DSM programs are profitable.

Because the ability of an incentive plan to decouple profits from sales is critical to a plan's success, a fourth and separate category of decoupling options is discussed. These decoupling options can be combined with any of the incentive plans to produce an overall package of regulatory reforms.

Conclusion

The following table presents a summary of the conclusions reached in this section. Listed across the top of the table are different assumptions of how state regulation might be structured. For example, the first column, "W/O Decoupling, W/O DSM Cost Recovery," describes a state which has not adopted revenue reconciliation mechanisms such as California's Electric Revenue Adjustment Mechanism (ERAM), or any of the other decoupling options, and which has no separate mechanism for recovery of DSM program costs. This means that the incentive plan selected must be capable of decoupling profits from sales while giving reasonable treatment to DSM program costs. Next, proceeding down the rows summarizes the capabilities of alternative incentive plans to produce a desirable result given the assumed status of regulation. A "yes" (Y) response means the incentive approach is a good candidate and attention should turn to the various ways to implement the general approach. A "no" (N) response means the approach is not a good candidate and a "maybe" (M) response means the capability of the approach to perform well depends on other matters.

This White Paper provides commissioners and commission staff with the background and framework needed to move forward with needed regulatory reforms. The remainder of the effort will be pursued with individual utilities in each state.

Clearly, the complexities and variations in regulation and the many factors in addition to regulation that influence utility decision-making and behavior cannot be distilled into one simple conclusion such as "fix the incentives." It would be as naive as it is tempting to say that all that is necessary is to fix the incentives and least-cost planning and energy efficiency will abound. Indeed, the disincentives are so potent that it would be even more naive to believe that least-cost planning or any significant investment in energy efficiency would be a reality without regulatory reform.

A debate, however, about the need for regulatory reform is a debate about the wrong question. Rather, the financial incentives of the existing system should be understood and compared with regulatory and legislative goals. Then, the debate should be about the gains and purposes served, and the beneficiaries of retaining the current system.

SUMMARY

ALTERNATIVE INCENTIVE PLANS

Features of State Regulation	**W/O Decoupling W/O DSM Cost Recovery**	**W/Decoupling W/O DSM Cost Recovery**	**W/O Decoupling W/DSM Cost Recovery**	**With Decoupling, W/DSM Cost Recovery**
Rate-of-Return Overall	*Y*	*Y*	*Y*	*Y*
Rate-of-Return DSM	*N*	*N*	*N*	*Y*
Rate-of-Return Bills	*Y*	*Y*	*Y*	*Y*
Shared Savings Resource	*N*	*M* *(See Note 2)*	*M* *(See Note 2)*	*Y*
Shared Savings Bill	*M* *(See Note 1)*	*Y*	*M*	*Y*
Bounty	*M* *(See Note 1)*	*Y*	*Y*	*Y*

NOTES:

Y - Yes, the approach can produce the right incentives.

N - No, the approach cannot produce the right incentives.

M - Maybe. Under some conditions the approach can be made to produce reasonable incentives.

(Note 1: This approach can address all costs only if average fuel costs exceed marginal fuel costs, which is rarely the case. Otherwise, the approach is sufficient only for low-cost measures.)

(Note 2: This approach is capable only for very low-cost DSM measures and very low-cost revenues.)

All cases assume the use of actual rather than estimated savings.

SECTION 1 -- THE PROBLEM

1.0 OVERVIEW

In the global race for energy efficiency the United States ranks 9th out of the 10 industrialized OECD nations.[1] We use twice as much energy to produce a dollar of GNP as Japan, West Germany, or Sweden. Only about half of the differences in energy use can be explained by factors that do not relate to energy efficiency. Responsible estimates show that cost-effective technologies available today can cut the nation's energy use by 20% (EPRI)[2] to 75% (Lovins)[3] without lifestyle changes or lower GNP growth.

Adopting cost effective energy efficiency as the nation's investment strategy would reduce the United States' annual energy bill by $27 to $120 billion. A savings of this magnitude would produce a substantial improvement in the global competitiveness of U.S. business and industry, our trade deficit, and our dependence on foreign oil.

In the coming decade, when energy policy will be increasingly driven by national and global environmental responsibilities, increased energy efficiency will result in direct and immediate benefit to the environment. Electric utilities now account for 20% of the gases linked to the atmospheric greenhouse effect, 70% of the nation's sulphur dioxide and 33% of the nitric oxide emissions that cause acid rain, and 50% of all nuclear waste.[4] Increasing the efficiency of our energy use, particularly electricity, can produce substantial environmental and health benefits at a fraction of the cost of adding pollution-control equipment or other mitigating approaches.

A growing number of policy makers and utility regulators are pursuing "least-cost planning" (LCP) in the battle against environmental and efficiency problems. LCP is a process of examining all electricity-saving and electricity-producing options to select a mixture of options that minimizes total consumer cost and that includes consideration of environmental concerns and other spheres of responsibility.

While least-cost planning principles have come a long way and have been adopted by a majority of states, the most vexing problem remains.[5] Specifically, how do regulators translate talk and ideas into action? Restated, how do we ensure that electric utilities fully embrace and implement least-cost planning in their own planning and investment decisions?

---

[1] *"Building on Success! The Age of Energy Efficiency," Worldwatch Paper No. 82, March, 1988.*

[2] *"Impact of Demand-Side Management on Future Customer Electricity Demand," Electric Power Research Institute (EPRI), EPRI EM-4815-SR, October, 1986.*

[3] *"The Great Demand-Side Bidding Debate Rages On." by Amory Lovins, Electricity Journal, Vol. 2, No. 2, March, 1989.*

[4] *"Acid Rain: Science and Control Issues," Environmental & Energy Study Institute, Washington, D.C., July, 1989; "Breathing Easier: Taking Action on Climate Change, Air Pollution, and Energy Insecurity," World Resources, Inc., Washington, D.C., 1989.*

[5] *According to EPRI Report # RP 2982-02, 43 States are either employing least-cost planning or are in the process of implementing a least-cost process.*

The impediment between LCP the idea, and LCP the practical reality, is the fact that the utility industry is responding rationally to its economic environment. Traditional state rate-setting regulation provides a strong economic disincentive to the utilities' implementation of least-cost plans or investment in energy efficiency programs. In particular, the demand-side elements of least-cost plans remain slighted. Indeed, the ratemaking process generally used in most states has the following unintended, but nevertheless perverse incentives.[6]

> *INCENTIVES INHERENT IN TRADITIONAL REGULATION*
>
> *1) Each KWH a utility sells, no matter how much it costs to produce or how little it sells for, adds to earnings.*
>
> *2) Each KWH saved or replaced with an energy efficiency measure, no matter how little it costs, reduces utility profits.*
>
> *3) The only direct financial aspect of regulation that encourages utilities to pursue cost-effective conservation is the risk that dissatisfied regulators may disallow costs.*
>
> *4) Purchases of power from cogeneration, renewable resources, or other non-utility sources add nothing to utility profits, no matter how cost-effective they are.*

These incentives are inconsistent with otherwise efficient investment by utilities in conservation or many supply-side options. While none were the conscious creation of the rate setting process as it evolved over the last century, these incentives are real and powerful, much so that little progress toward implementing large scale efficiency programs can be expected in an environment controlled by such powerfully opposing economic forces.

Regulators rightly insist upon the implementation of least-cost planning, but regulators also rule over a process which rewards utilities financially when they sell more power. Least-cost planning is likely to find little real success until ways are found to eliminate these mixed messages and align the financial interest of the utility industry with the goals of least-cost planning.

Finally, while the debate over which cost effectiveness test to apply to conservation investments may continue in a few states, the absurdity of the incentives inherent in the current regulatory process persists, and the need for reform is largely unaffected by who wins. Even if a commission selects the most restrictive definition of cost effectiveness, the fact remains that without regulatory reform, cost-effective conservation is unprofitable and every KWH sold adds to profits. Taking action to align the incentives should not be delayed.

---

[6] *Throughout this paper, the terms "earnings" and "profits" are used interchangeably. Except where the context is clearly to the contrary, adding or subtracting from earnings or profits refers to the incremental change in earnings or profits, not the absolute level of either. It matters not whether earnings or profits are 8% or 16%, or whether earnings or profits are above or below an allowed rate-of-return. In all instances, the paper focuses on the incremental increase or decrease in earnings (or profits) that flows from a specified course of conduct.*

1.1 THE DETAILS

What is it about the traditional rate setting process that produces all the wrong incentives?

1.10 Profits are not Fixed

First, as regulated monopolies, utilities are entitled to have their prices for electricity set at a level that will allow recovery of all prudently-incurred operating expenses and fixed costs. These fixed costs include such things as taxes, interest, and a reasonable rate of return, or profit on their rate base (calculated as their capital investment in power plants and other hardware, minus depreciation).

Actual profit levels earned by utilities are not etched in stone. Instead, state public utility commissions examine utilities' historical and forecast expenses in rate cases and set the price of electricity at levels expected to earn the utility a specified rate of return. However, once the price is set, i.e., between rate cases, the utility has an incentive to sell more electricity whenever its marginal revenue from a sale exceeds its marginal cost to produce and distribute the power. Because a utility is virtually always "between rate cases," and because fuel clauses and utility accounting practices assure that marginal revenue exceeds marginal cost, a utility can always improve its earnings by selling more power.[7]

If profits rise too high, regulators can step in and lower the price that the utility can charge for electricity, but only after time-consuming hearings in which the utility will generally oppose any change.[8] Even when rates are lowered, the utility is not required to give refunds or credits to customers to make up for past excess profits. Thus, a utility can keep all the profit it can make.[9]

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[7] *The result flows directly from the facts that prices are fixed and that fuel clauses are reconciled. The problem is unaffected by the procedure or assumptions used to fix prices; e.g., historic vs. future test year, or the level of sales or conservation used to set rates. The only aspects of regulation that make a difference are provisions that are reconciled, trued-up, or subject to deferred accounting and recovery. Even without fuel adjustment clauses, whenever prices are higher than the marginal fuel cost to produce power, the incentive to sell remains, albeit as a lesser incentive.*

[8] *Shortening the time to complete rate cases or increasing the frequency of rate cases is not a solution because utilities will still always be "between rate cases."*

1.11 The "Fuel Adjustment Clause"

In its understandable quest to maximize profits, a utility's most powerful incentive for selling more electricity is hidden in its regulatory fuel adjustment clause. Some 40 to 50 percent of the price of electricity is determined by the cost of fuel.[10] This cost is subject to considerable volatility, especially for oil and gas. To insulate utility shareholders from the impact of fluctuating fuel prices on earnings, nearly all states allow utilities to adjust customer prices periodically so that changing fuel costs do not affect profits.[11]

1.12 No Reason to Conserve Fuel

The "fuel adjustment" protection operates whether a utility's total fuel bill increases because of rising prices, or because more fuel is used to satisfy an increased demand for electricity. A utility that spends more than it has projected on fuel can raise the price of all electricity to spread the excess cost among its customers. If, however, it spends less than projected, the utility must pass on the savings to consumers through lower rates. Thus, the utility has little (or no) direct economic incentive to conserve fuel or to purchase the lowest cost fuel.[12]

Utilities even make money when they sell power for what initially appears to be less than it costs to produce. For example, to meet increased demand during peak periods, a utility may crank up a relatively inefficient diesel generator that consumes 10 cents worth of fuel to produce one kilowatt-hour (KWH) of electricity. The regulated price of power might be seven cents per KWH, which represents five cents in fixed costs and two cents allotted for the utility's "average" fuel costs. But the utility can recover the extra eight cents in fuel costs later (that is, the generator's ten-cent fuel cost minus the two-cent average fuel cost) by invoking the fuel adjustment clause to raise rates.[13] Meanwhile, the five-cent non-fuel, or base part of its rate remains in place.[14]

---

[9] *To be sure, the system also provides an incentive to reduce some types of costs. This aspect of the current regulatory system should not be lost when searching for new regulatory mechanisms.*

[10] *In 1987, the national average price of electricity was about 6.5 cents/KWH.*

[11] *Annual Report on Utility & Carrier Regulation, 1986 Edition, National Association of Regulatory Utility Commissioners (NARUC), Washington, D.C., Table 12, pp.415-416, supplemented by telephone conversations.*

[12] *As always, the risk that regulators will detect and punish wasteful practices will be present.*

[13] *In effect, the utility charges customers 15 cents for the KWH, 7 cents now and 8 cents later through the true-up provisions of the fuel clause.*

[14] *There are at least two reasons perhaps not to eliminate a fuel adjustment clause entirely, and adopt declining block rates with the tail block rate equal to or less than the utility's marginal fuel cost as a solution to the problem. First, there may be sound reasons for retaining some aspects of fuel clauses. For example, without fuel clauses, for utilities dependent on oil or gas, volatile fuel prices would be the primary determinant*

1.13 Recovery of Fixed Cost

As a general matter, in the short term, incremental sales of power to an existing customer add no costs other than the fuel needed to produce the power.[15] But, the combination of price-setting and accounting practices means that each KWH sold includes a piece of non-fuel cost-recovery even when there are no additional non-fuel costs.[16] This means each KWH sold adds to earnings.

The incremental contribution to the bottom line occurs whether the sale takes place before or after the utility has reached its projected level of sales. A nickel made on the sale of the first KWH is the same as a nickel made on the sale of the millionth or billionth KWH.[17]

Similarly, the incremental effect on profits remains undisturbed by a utility's achieved rate of return. Stated most simply, an incremental five cents is five cents whether it comes when the utility is earning an 8%, 12%, or 16% rate of return. While much of this discussion has described the effect of sales on profits, the effect of not selling power is the same. Each KWH not sold, or conserved, has a negative effect on earnings.[18]

---

of profits. If utilities have no significant control over fuel prices, little could be gained by exposing them to this risk. Second, setting tail block rates at or below the cost of fuel would give customers the wrong price signal and would therefore seriously undermine the goals of LCP. For LCP to work, customer prices for incremental consumption should reflect the full cost of new resources.

[15] *This is not typically the case for sales to new customers. New customers require new meters, poles, wire, and additional customer accounting costs. Consideration of incremental capacity costs is more complicated but generally does not affect the conclusions reached here. First, in many states, purchased capacity, or at least some types of purchased capacity such as purchases from qualifying facilities, are included as part of the fuel adjustment mechanisms. Second, recovery of the cost of new utility construction (including carrying costs) is generally deferred. This, together with the substantial control utilities have in most states over when to file a rate case, tends to reduce or eliminate these costs as an element in an analysis of incentives. Finally, shortages of generator capacity rarely occur, and when they do, they persist for a short period of time. More often than not utilities have more than the minimum amount of capacity needed to maintain reliability.*

[16] *Even when the marginal sales price is equal to or less than the marginal fuel cost, utility accounting continues to treat a part of the sales price as a contribution to non-fuel cost.*

[17] *A common misconception is that the disincentive to conserve exists only if the utility has sold less electricity than was assumed when prices were set. The incremental effect on earnings of sales or conservation is the same regardless of the level of sales.*

[18] *The financial impact of an investment in energy efficiency is very large, about twice that of ordinary operating expenses such as plant maintenance or tree trimming. The table in Section 3.101 shows that a $1.6 million investment in DSM reduces earnings by $4.0 million. In comparison, increasing tree trimming spending by $1.6 million would decrease that year's earnings by $1.6 million.*

SECTION 2 --SELECTING AND IMPLEMENTING REGULATORY REFORMS

Perfection is the Enemy of the Good

A regulatory reform plan and its implementation should be compared to the existing regulatory system. For example, under the current regulatory system, utilities operate under financial incentives which encourage all opportunities, whether efficient or inefficient, to sell electricity. Regulators considering a regulatory reform proposal which may discourage utilities from promoting load growth should not ask if the plan is ideal, but whether such an incentive structure is better or worse than the existing incentive structure inherent in the current system.

Similarly, no regulatory system can eliminate the possibility that utilities might engage in actions which, when undetected by regulators, unjustly enrich the utility. The decision to implement an incentive plan which does not eliminate this possibility should be based on whether the motivation to engage in imprudent behavior is great, or whether such behavior would be more difficult to detect in the new plan than it is under the existing system.

There are many solutions available to state regulators to correct the incentive structure of regulation. This section presents a common framework of the most important considerations against which to test and evaluate each current and future alternative solution.[19] Additional considerations are discussed in Appendix A.

2.0 FIRST PRINCIPLES

Incentives and disincentives embedded in the current system of regulation present a serious obstacle to the successful implementation of LCP. NARUC concluded that regulatory reform was needed to remove the disincentives to LCP and to make a utility's least cost-plan its most profitable course of action.[20] It follows, therefore, that the single overarching standard against which proposed incentive plans should be measured is whether the new financial incentives will encourage the utility to implement successfully a least-cost plan.[21]

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[19] *Throughout this section aspects of particular incentive plans are used to help explain the concepts. A more complete discussion of the available options are described and analyzed in Section 3 and Appendix A.*

[20] *See NARUC Resolution, Appendix C.*

[21] *Even though the goal is to create a regulatory structure which is completely compatible with least-cost planning, decisions to proceed with particular proposals should be based on relative improvements to the existing system of regulation. Every proposal, no matter how well conceived, will have its weaknesses and peculiarities. Nevertheless, the plan should be judged in relation to other proposals and the extraordinarily bad incentives in the existing system of regulation. While the ultimate goal is to have a plan which is completely consistent with least-cost planning, as a practical matter, states should pursue proposals which significantly improve the status quo.*

2.00 Profit Maximizing Strategy

The test for an effective incentive proposal lies in the answer to this question:

> *Viewed from the perspective of the utility, what course of action would be consistent with a profit-maximizing strategy?*

The utility's most profitable course of conduct should be to implement successfully a least-cost plan. Commissioners should seek an incentive plan which satisfies this most important criterion. If the utility's most profitable course of conduct is to pursue programs that do not reflect a cost-minimizing plan while still promoting sales which are not cost-effective, the incentive plan fails to meet the primary criterion.

Be Creative

Consider as many alternative approaches as possible. As the discussion in Section 3 shows, many different approaches have already been identified and there will be more. Regulators will devise new, creative, and more effective plans if they focus on the particular needs and priorities of their state and do not limit themselves to conventional solutions to the problem.

Often the analyses, discussion, and design of specific incentive proposals begin with quantifying the negative impact DSM programs have on the utility's earnings. The analysis generally separates the adverse earnings impact into three parts: lost revenues, DSM program cost-recovery, and incentive components.

Next, separate incentive plans are designed to address each of the three elements.[22] This approach is not necessarily wrong, but it tends to limit the breadth of plans available for consideration and creates the risk that plans taking a different approach will be rejected solely because the plan does not fit a particular mold. To avoid these limitations, do not allow the framework, or specific deficiencies, of the current regulatory system to impose artificial constraints on the design or selection of incentive plans.

An example of a plan which approaches the problem in an entirely different manner will illustrate how regulation might be changed to produce reasonable incentives using relatively simple solutions. Consider a state which, like most, has a reconciled fuel adjustment clause, full recovery of all direct DSM program costs, and which has relatively high marginal fuel or production costs.[23] Assume that "Utility X" has a marginal revenue or marginal price of five cents per KWH and a marginal fuel cost of six cents per kilowatt-hour.[24] At first blush, a marginal KWH sold produces a net loss of one cent and "Utility X" would have no incentive to pursue this sale. On closer examination, however, the existence of the reconciled fuel clause means the entire six-cent marginal fuel cost will be returned to the utility. Because the utility is held harmless from the increased fuel cost, the sale that looked like a loss is, in fact, a profitable sale.

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[22] *It is generally believed that the job is done and the incentives are right when lost revenues have been restored and the utility is made whole for its efforts in the DSM programs and a bonus is provided. In fact, this may or may not be true depending upon how a program is structured.*

[23] *The term "reconciled" is used in this paper in a number of areas, most generally relating to fuel clauses. A fully reconciled fuel adjustment clause means utilities recover dollar for dollar all fuel expenses including interest on fuel costs. Several states use partial reconciliation which can take many different forms. In some*

If, on the other hand, "Utility X" pursues conservation, even zero-cost conservation, it will experience a net loss of earnings. The KWH saved means a five-cent revenue loss to "Utility X" which is not offset by any cost reduction because the six-cent fuel cost saving is passed on entirely to customers. "Utility X" realizes a net loss. Thus, the utility has an incentive to pursue a five-cent sale rather than zero-cost conservation, even though the KWH sold "cost" six cents to produce.

Consider how the incentives shift if the fuel clause reconciliation process is changed slightly and fuel costs continue to be reconciled for changes in fuel prices, but not fuel quantity.[25] In this case, the incremental six-cent fuel cost is borne by the utility if it sells another KWH, and it is a cost savings to the utility if it conserves a KWH. Under these conditions, an incremental sale produces a one-cent loss, and zero-cost conservation produces a profit. With this simple change to just one aspect of the fuel adjustment clause, the sale of the marginal kilowatt-hour would not be a profit-maximizing strategy. Instead, the new profit-maximizing strategy for "Utility X" would be to pursue energy conservation over increased sales.[26]

Notice that in this example of an "incentive plan" no elements of the plan restore lost revenues or which provide a separate DSM incentive. Yet, the utility's incentives are tied to the successful implementation of DSM programs.[27]

In summary, like good people, good incentive plans can take a wide variety of shapes, sizes, and personalities. Regulators, utilities, and others should remain tolerant and

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states, interest costs are not allowed; in others, a portion of the difference between projected and actual fuel cost is left at the utility's risk, to provide an incentive to the utility to minimize fuel costs. For example, in New York a utility recovers only 80% of the difference between projected and actual fuel cost. The manner and extent of reconciliation is a very important consideration in evaluating incentive plans.

[24] *The five-cent price might be two cents of non-fuel base revenue and three cents of average fuel.*

[25] *If the utility's fuel bill increases because fuel prices increase, it continues to be protected by the reconciliation, or true-up, provisions of the fuel adjustment clause. If, however, the total fuel cost rises because sales increased, the utility must bear the extra cost. Likewise, the utility keeps any reduction in fuel cost caused by lower sales resulting from successful DSM efforts.*

[26] *Recall that "Utility X," like most utilities, recovers its DSM program costs separately so the six-cent fuel cost saving is not offset by the cost of conservation. In addition, recall that for this utility the marginal fuel cost exceeds its marginal revenue. This condition is very rare given today's relatively low fossil fuel costs.*

[27] *The effectiveness of this approach depends on the relationship of marginal fuel cost to the price of electricity. If the price of power exceeds the marginal fuel cost, this approach is only partially effective.*

receptive to different approaches.

2.01 Unlimited Scope

Ideally, an incentive plan will encompass all aspects of LCP. Trying to simplify the task of finding the right incentive plan by limiting the scope of the undertaking is probably a mistake.

Limitations can take several different forms. For example, regulatory reform efforts could be targeted only at DSM instead of both demand- and supply-side aspects of LCP.[28] Limiting efforts to making conservation profitable and not trying to remove the incentive to sell more power is another example.[29]

Limiting the scope of the undertaking will narrow the range of options available, and may needlessly eliminate approaches that fit well with ratemaking or accounting practices unique to the state.[30] Moreover, these types of constraints would make it more difficult to get achieve optimum overall incentives, even when successfully addressing the narrow issues. The existing "incentives" are that:

> *1) all sales, whether cost-effective or not, add to earnings; and*
> *2) all conservation, whether cost-effective or not, is unprofitable*[31]

If a plan is limited to making DSM desirable, both sales and conservation would be profitable. While incentives limited to DSM represent a clear improvement, they stop short of producing a strategy that makes pursuing a least-cost plan the most advantageous course of action.

2.02 Measurement

Incentives resulting from LCP will be greatly influenced by how, what, and when to measure. Consequently, measurement issues should not be viewed as a mere technical issue when policy makers discuss the merits of different incentive options. Many incentive plans, especially those limited to the demand side, require measurement of both capacity and energy savings. Plans that explicitly restore DSM-related lost revenues also generally require a measure of DSM-induced revenue loss.[32]

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[28] *Environmental externalities, risk, and diversity are examples of matters which are generally not incorporated into any incentive plans nor are these matters which are reflected in the economic incentives embodied in existing regulation.*

[29] *To date, most proposals tend to be limited to making DSM programs profitable and do not address the incentives to increase sales or any aspect of supply-side options. This should come as no surprise because the existing incentives for DSM are most skewed.*

[30] *For example, an option which changes portions of the fuel adjustment clause would affect both DSM programs and sales incentives. States that narrow the scope of incentive plans to only DSM incentives will needlessly foreclose the use of this type of approach.*

[31] *The aim is to make only cost-effective selections, whether demand-side or supply-side, the profitable choice.*

A combination of engineering and economic judgments instead of actual measurement of capacity and energy savings may be adequate for the purposes of program design. By contrast, regulatory incentive proposals not measuring actual achievements may result in the wrong underlying incentives.[33]

For example, consider the substantially different incentives produced by an electric water heater insulation program under two incentive plans where the only difference is how and when program savings are measured. The first plan has KWH savings based on extrapolating test data, engineering estimates, or measurements made at other times (or in other states). The second plan is the same in all respects except that program savings are based on random, statistically valid, on-site measurements of utility-installed measures.

Suppose, under the first plan, an agreement is reached that an electric water heater insulation blanket will yield 600 kilowatt-hours per year in energy savings. Under this plan, the utility will be allowed to recover direct and indirect program costs, 600 KWH's worth of lost revenues, and an incentive based on any rational approach.[34]

What happens when the utility actually achieves 700 kilowatt hours in savings through better quality-control or other efforts under its control? It loses money!

In contrast, what happens when the utility selects poor quality contractors and has inadequate quality-control efforts? Actual savings drop to 500 or 400 KWH per year, and utility profits increase!

Profits increase because the utility still recovers lost revenue based on an assumed 600 KWH savings when in fact not all of these revenues were lost. In addition, the incentive portion is unaffected by the lower actual savings.

Solely as a consequence of a measurement decision, the utility's profit maximizing strategy would be to select measures which would test well under the measurement criteria imposed, but perform poorly.

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[32] *California's ERAM is a time-tested approach which does not require the identification of DSM-induced lost revenues. Actual and projected (allowed) revenues are reconciled regardless of the cause of any discrepancy. Thus, the only measurement required is of actual revenues which is simple and verifiable.*

The plan described in Footnote 23, which consisted of changing the fuel clause, is an example of another approach that does not require the measurement of lost revenues. In that plan the fuel cost savings kept by the utility more than offset lost base revenues.

[33] *Cost/benefit analyses of measurement should not be forgotten.*

[34] *For the purpose of this example, the exact nature of the incentive element is not important. The analysis is the same whether it is a shared savings approach or a fixed payment for each KWH saved.*

Under the second plan, where actual measurements of achieved results are used, what happens if the utility is able to achieve 700 KWH in savings? Profits go up. As it should be, earnings go down if the savings are less than 600 KWH. The profit-maximizing strategy is to get more savings rather than fewer.

2.03 Framework for Analysis

To simplify the evaluation process, start with a list of questions that describe important considerations. Consider:

> *What happens to profits if the utility sells another KWH?*
>
> *What happens to earnings if sales are reduced by one KWH through conservation programs that cost $0.01 per KWH?, $0.02?, $0.10?*
>
> *What happens to profits if a utility invests in load control and shifts a KW from on-peak to off-peak?*
>
> *What happens if the utility pursues a power marketing strategy?*
>
> *What happens if the utility selects the more costly of two supply-side options; or the more costly of two demand-side options; or a supply-side option which is more costly than a demand-side option?*

Starting with just one proposed incentive plan, test the incremental effect on earnings of the alternative courses of action suggested by the questions.[35] The combination of the answers to the questions will unveil the utility's profit-maximizing strategy for that particular incentive plan. When the functioning of one incentive plan is understood, perform the same analysis using another incentive plan.

The analysis should not start with a particular course of action, i.e. conservation program "X", and then compare that program's effect on profits under alternative incentive plans. This approach asks the wrong question, and it is unlikely to lead to a useful answer. Knowing that conservation program "X" is more profitable under Plan "A" than it is under Plan "B" or under the existing system of regulation says nothing about the profitability of sales or conservation under Plan "A".

Thus, to evaluate the desirability of a plan, begin with a proposed incentive plan and, regardless of any other plan, test it against a wide range of conduct, and identify the profit-maximizing strategies. If those strategies are consistent with a desired course of conduct, consider it to be a good candidate while you proceed to review other proposed plans.

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[35] *When answering the questions, be very aware of all of the specific ratemaking and accounting practices used in the state. Of special importance are 1) the exact workings of fuel and purchased power clauses and associated reconciliation provisions, 2) any other ratemaking provisions allowing deferred expense accounting, including deferred accounting for conservation cost; and 3) rate design and revenue accounting provisions which affect the level of base revenue contributions of marginal sales of power to each customer class and for each rate period for time-of-use rates.*

2.1 PROBLEMS, BENEFITS, AND GOALS

Identifying a profit-maximizing strategy is the most important test of any incentive proposal.

The next set of considerations are also quite important and should be given serious attention while developing or selecting the best plan for each state. The considerations are discussed in general order of importance:[36]

Decoupling profits from sales;
Cost minimization;
Administrative simplicity;
Fuel switching; and
Balance.

A final group of considerations which are of slightly less importance are discussed in Appendix A. These considerations are as follows:

Predictability;
Environmental costs;
Non-participant impacts;
Skimming the cream;
Avoiding gamesmanship; and
Distribution of incentives.

2.11 Decoupling Profits from Sales

Under current regulation increased sales always mean increased profits. As long as every incremental KWH sold adds to profits, a strong likelihood remains that a profit maximizing strategy will lead to more sales and less DSM, even if DSM programs are profitable.[37] Thus, incentive plans should be evaluated to see how effectively sales are decoupled from profits.[38]

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[36] *To be sure, there are many, often conflicting, forces which influence utility behavior. Changing the financial incentives is only one, albeit the most important, area that requires attention by regulators.*

[37] *Even where a plan succeeds in making a KWH conserved more profitable than a KWH sold, perceived risks and unfamiliarity with DSM programs will tend to bias a profit-maximizing strategy toward sales.*

[38] *This does not mean that all sales of electricity should be discouraged for its own sake. Sales, however, should not be profitable regardless of the cost of electricity or the cost of alternatives, including energy efficiency.*

Decoupling can take either of two forms. First, decoupling may merely eliminate the incentive to increase sales. This approach generally holds the utility harmless from fluctuating sales levels and provides no financial incentive or disincentive to increase or decrease sales. There are several different approaches to accomplish this first type of decoupling. The most widely known is California's Electric Revenue Adjustment Mechanism (ERAM), and it is discussed in Section 3.41.[39]

There are also other, very different, approaches which can accomplish very similar results. For example, fuel revenue accounting changes implemented in Maine set the non-fuel revenues from marginal sales equal to, or near, zero. The result is that incremental sales do not add to profits. This practice has been accomplished by changing accounting rules that generate no changes in retail prices.

Interestingly, plans which incorporate recovery of only lost revenues specifically attributed to efficiency programs do not decouple profits from sales. At most, this approach links conservation to profits the same way sales are already linked to profits. The disincentive towards energy efficiency is removed, but the overall incentive to sell power remains intact. Sales are always profitable regardless of the cost of producing the power.[40]

The second form of decoupling is with the use of plans which provide incentives when sales are decreased by cost-effective DSM measures and disincentives when sales increase. For example, plans which increase a utility's rate of return if customer bills decrease, and decrease rate of return when customer bills increase can decouple profits from sales even though there is no lost revenue adjustment. Because only a few incentive plans decouple profits from sales in this fashion, it is necessary to combine most incentive plans with separate decoupling options to produce the most desirable overall incentives.

2.12 Cost Minimization

Will the proposed program encourage the utility to deliver conservation programs at the lowest cost to consumers?

Consider two incentive plans, both of which measure actual achieved conservation results. The first pays the utility a predetermined, fixed amount for each KWH saved. The fixed payment will be less than the utility's avoided cost and will therefore help assure that only cost-effective efficiency is purchased. The payment covers direct program cost and an incentive for the utility. The second plan pays the utility 110% of its actual program costs for each KWH actually saved.

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[39] *See also Cavanagh. "Responsible Power Marketing in an Increasingly Competitive Era." Yale Journal on Regulation, New Haven: 1988. Vol. 5,No. 331.*

[40] *Oddly, consumer advocates often favor this approach because it is more limited in scope than an ERAM type approach. In fact, this approach presents the worst choice for consumers. First, this approach does not decouple profits from sales, and second it is an adjustment that always works in one direction, providing more revenue to the utility. In contrast, ERAM does decouple and it refunds money to consumers if sales increase.*

To maximize profits under the first plan, the utility will try to reduce its cost of saving KWHs to maximize the difference between the fixed payment it receives and its out-of-pocket costs. To maximize profits under the second plan, the utility would get as much conservation as it could, regardless of the cost.

Generally, plans should be designed to encourage utilities to obtain DSM savings at the lowest possible cost.

2.13 Administrative Simplicity

Achieving significant reform of a regulatory system that has been in place for nearly a century will require substantial public and political support. Gaining the needed support will be difficult if the proposed plan is too complex or obscure.

Incentive plans should be simple and efficient to administer, or the cost of regulation may outweigh the benefit. The cost of regulation includes items such as the cost to the regulatory commission of administering the system, the cost to the utility of collecting and reporting any additional information, and the cost to all parties of participating in any new regulatory proceedings that may be needed.

In practice, this principle means avoiding incentive plans that rely on complex formulas or unverifiable measurements. For this reason, commissioners may want to avoid approaches which require separate proceedings in favor of plans which can be implemented within the framework of existing regulations.

2.14 Balance

Incentive proposals should have a reasonable risk/reward relationship. Once measurement criteria are set, superior performance should yield higher earnings, and similarly, inferior performance should yield lower earnings. The plan should not provide utilities with unreasonable opportunities to profit at the unnecessary expense of ratepayers, nor should the plan deprive the utilities of a reasonable opportunity to earn a fair return.[41]

To gain public acceptance and increase the likelihood that an incentive plan will produce the desired result, an incentive plan should operate symmetrically, i.e. rewarding superior and punishing inferior performance. Incentive plans which only reward utilities for good performance and has no effect when performance is poor will be criticized as being unfair and ineffective.

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[41] *While this discussion may seem self-evident, there are plans discussed in Section 3 that run afoul of this consideration.*

SECTION 3 -- ALTERNATIVE APPROACHES

3.0 GENERAL

This section describes and evaluates alternative approaches to changing the incentives inherent in the current regulatory system. Incentive proposals have been grouped into three general categories based on the approach taken. The categories follow:

Rate-of-Return Adjustments
Shared Savings
Bounty

For each of these approaches, different performance criteria are available to address one or more special concern. All the possible modifications to each approach will not be covered here. Regulators, for the most part, can mix and match different components of incentive plans until they find a desirable group of features.[42]

Although the ability of an incentive plan to decouple profits from sales is critical to a plan's success in changing investment and other decisions, many of the plans fail to accomplish the desired decoupling. Therefore a separate category of decoupling options follows the discussion of the three categories of plans. These decoupling options can be used with any of the incentive plans to produce an overall package of regulatory reforms.

Three questions should be asked when structuring an incentive plan:

One: Will the incentive plan make available enough additional earnings to offset the existing disincentives and which alternative course of action will maximize earnings?[43]

Two: Does the incentive plan decouple profits from sales or must it be combined with a decoupling option?

Three: What behavioral changes does the plan encourage:
-energy savings or spending?
-cream-skimming, fuel switching, cost-minimization?
-can the plan accommodate considerations of environmental externalities?

The first two questions and the most important elements of the third question are discussed in this section. Secondary considerations and factors that are common to all plans are discussed in Appendix A.

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[42] *Specific proposals that have been the subject of publications or regulatory decisions are described only in general terms, with citations to more specific materials.*

[43] *Net revenues from a plan equal the incremental revenue minus direct and indirect costs, e.g. lost revenues and DSM program costs.*

Throughout Section 3, simple quantitative calculations are used to illustrate the different plans' potential to produce enough incremental earnings to offset the disincentives of the current system. To simplify the discussion, the following uniform assumptions are made:

Illustrative Utility Statistics[44]

1) average price	\$.07
2) average fuel cost	\$.02
3) average non-fuel cost	\$.05
4) marginal fuel cost	\$.03
5) conservation cost	\$.02[45]
6) rate base (total)	1 billion
7) allowed rate of return	12% overall
8) cost of equity	14%
9) cost of debt	10%
10) capital structure	50/50
11) annual sales	8 billion KWH
12) annual revenues	\$560 million

Except as noted in the discussion, the state is also assumed to have a fully reconciled fuel adjustment clause.[46] As the following table shows, the incentives are improved by the elimination of fuel adjustment clauses, but the overall direction of the incentives is unchanged.

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[44] *These assumptions are generally consistent with national averages shown in Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry, 1987.*

[45] *Each \$1.00 of program cost is assumed to save ten KWH per year for five years. Total savings over the five-year life are 50 KWH, producing a simple average cost of \$.02 per KWH. Thus, a \$.10 investment in year one will produce one KWH of savings each year for five years.*

[46] *Whether direct program costs are recovered through expensing, ratebasing, or amortization makes no significant difference.*

Incremental Earnings Impacts[47]

	w/fuel clause	w/o fuel clause
Incremental KWH sold	$.05[48]	($.04)[49]
Incremental KWH saved w/DSM program cost recovery	($.05)[50]	($.04)[51]
Incremental KWH saved w/o DSM program cost recovery	($.07)[52]	($.06)[53]
Incremental KWH saved w/rate base treatment	($.0488)[54]	($.0388)[55]

Without a fuel clause the magnitude and direction of the short-term incentives depend on the relationship of retail rates to marginal fuel costs. If retail rates exceed marginal fuel costs, which is the case in most jurisdictions, incremental sales are profitable. With a fuel clause, incremental sales are profitable regardless of the relationship of retail prices to marginal fuel costs.

3.1 RATE-OF-RETURN ADJUSTMENTS

The most common approach to providing incentives for LCP or energy efficiency investment is to adjust the utility's allowed rate of return (either on equity or total return) in relation to a specified accomplishment, such as achieving a target level of conservation, a reduction in customer bills, a specified level of DSM spending or some other indicator of performance.

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[47] *This is a simplified illustration of the earnings impacts of DSM programs under typical rate-setting procedures with and without a fully reconciled fuel clause, and with or without separate recovery of program costs.*

[48] *The entire non-fuel component is realized because fuel cost is fully recovered from customers.*

[49] *Utility receives $.07 from retail sale, less the full $.03 marginal fuel cost.*

[50] *The entire non-fuel component is lost. The $.03 marginal fuel cost savings is realized by customers.*

[51] *The utility loses the $.07 retail rate but save $.03 in fuel costs, thereby realizing a net loss of $.04.*

[52] *Same as note 43 except the utility also incurs $.02 cost for DSM program.*

[53] *Same as note 44 except the utility also incurs $.02 cost for DSM program.*

[54] *Same as note 43 except the utility receives return: 12%on the $.10 of rate base associated with one KWH saved. This further assumes no lag in the DSM investment and cost recovery.*

[55] *Same as note 44 except the utility receives return on the $.10 of rate base associated with one KWH saved.*

In some cases, the adjusted rate of return is applied to the total investment (rate base), and in others, only toward the investment in demand-side measures. These two approaches are discussed separately, followed by a discussion of the use of return adjustments based on customer bills.

3.10 Rate-of-Return Adjustment--Total Rate Base

3.100 General Description

This subsection addresses incentive plans that operate by adjusting the utility's allowed rate of return on its total investment. Within this category there are several variations which establish different performance criteria (or benchmarks) for judging whether and how much to change the utility's rate of return.

Performance criteria discussed thus far tend to fall into two groups. First, adjustments to the rate of return are compared to the utility's ability to achieve a specified level of capacity (or energy) savings. Second, rate-of-return adjustments are measured in relation to changes in customer bills.

Programs which relate rate of return to capacity or energy savings targets can be measured in a number of ways. The particular approach selected will determine the incentive characteristics of the plan. Table 1 summarizes the nature of the underlying incentives for four different performance measurements.[56]

Each of these performance criteria, one based on estimated savings and the others representing different ways to measure achieved savings, produces different incentives. The four performance criteria shown across the top of Table 1 are as follows:

(1) Estimated Savings - DSM savings are based on engineering estimates, experience from other areas, or otherwise agreed-upon levels established in advance. The primary difference between estimated and actual savings is the former does not reflect the savings achieved by a utility's programs.

(2) Actual Savings - DSM program results are measured directly by techniques such as after-the-fact metering of statistically valid samples of installations. In some situations actual savings may include engineering estimates. In general, "actual savings" are the product of careful program evaluation and reflect the savings achieved by the actual DSM accomplishments of a utility.

(3) Load vs.Forecast - DSM results can be measured indirectly on an aggregate basis by comparing the utility's actual load against its load forecast. The

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[56] *These are not the only four performance criteria which could be used.*

comparison determines which goals were consistent with DSM and other LCP efforts.[57] The differences between the actual load growth and the adjusted forecast would be used as a measure of overall DSM program performance.

(4) Efficiency Measure - Aggregate program performance can also be judged in terms of measures of efficiency, either BTU per dollar GNP, KWH per dollar GNP, KWH per customer, or other similar scales. The difference between actual and adjusted forecast efficiency is the yardstick.

TABLE 1

RATE OF RETURN ADJUSTMENTS
(Total Investment)

PERFORMANCE CRITERIA	**(1) Estimated Savings**	**(2) Actual Savings**	**(3) Load vs. Forecast Difference**	**(4) Efficiency Measure BTU/$GNP KWH/Customer**
DSM INCENTIVES	*Perverse*	*Good*	*Good*	*Good*
DECOUPLING	*No*	*No*	*Yes*	*Yes*
SCOPE	*DSM Only*	*DSM Only*	*DSM Only*	*DSM and partial supply-side with certain efficiency measures*
COST MINIMIZATION	*No-Unless payment includes program cost recovery*	*No-Unless payment includes program cost recovery*	*No-Unless payment includes program cost recovery*	*No-Unless payment includes program cost recovery*
ADMINISTRATIVE SIMPLICITY/COST	*Low cost*	*Low incremental cost if good program evaluation is done*	*Medium to low*	*Medium to low*

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[57] *Before making the comparison, the projected load would have to be adjusted for differences in weather, economic conditions, and other relevant factors which are outside the utility's control.*

3.101 Incentive Potential

Adjusting the rate of return on a utility's overall investment may produce enough incremental revenue to offset the disincentives in the current ratemaking process. Applying the typical utility data to a modest utility DSM program produces the following results:[58]

Annual DSM Savings (1% of sales)	8 million KWH
DSM Cost (8 million KWH x $.02)	$1.6 million
Lost Revenue (8 million KWH x $.05)	$4.0 million = = = = = = = = = = = =
Total	$5.6 million
Incremental Earnings Each 1% change in Rate of Return (Overall Return) (1% x $1 billion)	$10 million
Required Change in Rate of Return to Produce $5.6 million of Earnings	.56%

These figures show that relatively small changes to a utility's allowed rate of return can produce enough revenue to offset DSM program costs and lost revenue. Any change in return over the amount shown in the table will provide a positive incentive.

Finally, combining this type of approach with other DSM program cost recovery, lost revenue adjustments, or decoupling approaches means the required change in the rate of return will be smaller than the table suggests. The required change in rate of return would also be smaller in a state without a fuel adjustment clause.

3.102 DSM Incentive

Will the performance criteria provide incentives that operate in the right direction?

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[58] *This represents about 0.3% of the utility's total revenues, and is slightly less than the relative level of DSM spending for California utilities. It is about 10% of the relative spending of several New England utilities.*

As discussed in Section 2, approaches which rely on engineering estimates, agreed-upon program benefits, or other estimated savings (Table 1, Column 1) tend to produce perverse incentives. Under these plans, the utilities' financial rewards are negatively affected by achieved results and positively affected by the number of installations.

Financially, the best course of action for a utility under this scheme would be to implement a large DSM program which produces few results. For example, the company might install a large number of devices which, because of inaccurate estimates, free-rider effects, or low quality materials, produce lower efficiency improvements.

The previous table shows that it requires a .56% (56 basis point) change in the utility's allowed rate of return to compensate for all direct and indirect DSM costs. This change produced $5.6 million in increased earnings which exactly offset DSM program costs and lost revenues. The following table illustrates the incentives produced by a plan which uses estimated savings. The table uses with the $5.6 million incentive payment from the previous table, and shows what would happen when actual DSM savings are 50% higher and, alternatively, 50% lower, than estimated.

DSM SAVINGS

Original Increase in Earnings	$5.6 million
Incremental Earnings with 50% less savings (8 million KWH x 50% x $.05)	$2.0 million
Incremental Earnings with 50% more savings (8 million KWH x 50% x $.05)	($2.0) million

In sharp contrast, each of the three performance criteria in Table 1 which rely on actual measurements will produce incentives which are proportional to performance. If achieved results increase (either because of the number or quality of installations), whether measured by metering, load reductions, or efficiency improvements, the rate-of-return adjustment also increases.

3.103 Decoupling

Are any of the variations of rate-of-return adjustments capable of decoupling profits from sales without relying on a separate decoupling option?

To be fully effective, an incentive plan should decouple profits from sales. As shown in Table 1, the first two performance criteria (which rely on either actual or estimated DSM impacts) do not decouple. In both approaches, increased sales produce increased earnings and have no impact on the apparent success of implementing DSM programs.[59]

The two remaining approaches (actual/forecast load, and actual/forecast efficiency) will accomplish decoupling. In both performance criteria, increased sales reduce the utility's measured results, which means lower profits or negative incentives.

3.104 Scope

Do any of the performance criteria allow the plan to extend to matters beyond DSM programs?

As summarized in Table 1, the first three approaches do not extend beyond demand-side programs. The fourth approach which measures energy efficiency can, however, be used to incorporate at least some efficiency opportunities on the supply side. For example, measures such as BTUs of utility fuel input per customer would capture changes in power plant efficiencies, i.e., heat rates. Because of the operation of fuel adjustment clauses, utilities currently have little or no incentive to pursue these opportunities.

In fact, with reconciled fuel adjustment clauses, utilities are held harmless from increased fuel costs resulting from plant inefficiency. Meanwhile, the deferral of maintenance costs, which causes deteriorating plant efficiency, improves short-term earnings. A plan that creates supply-side efficiency incentives would be an improvement.[60]

3.105 Administrative Simplicity

Do any of the performance criteria pose unreasonably high administrative costs?

The administrative costs of the estimated or measured program performance criteria would be relatively high if savings estimates are made on a program-by-program basis. The incremental costs, however, would be relatively low if the information is already developed for program evaluation or other purposes.

Measuring savings on an aggregate basis may impose fewer procedural and administrative costs on utilities and regulators than disaggregated program-by-program evaluations, assuming that regulators are unable to devote staff resources to program evaluation. An incentive plan that is based on aggregate performance would place the burden on utilities to use more detailed program evaluations to decide which programs to expand, contract, or modify to achieve the best overall results.

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[59] *Depending on the precise method of measuring achieved results, it might not be in the utility's financial interest to pursue programs that increase the load of customers who participate in DSM programs. For example, if demand-side program benefits are measured by comparing consumption of participants vs. non-participants, it would not be in the utility's interest to pursue a load-building program that might be favored by participants in DSM programs. Such a program would tend to increase consumption of the participating customers and thereby reduce the measured savings of a DSM program. This conclusion, however, is very sensitive to the precise method of measurement selected.*

[60] *Incentive plans based on revenue per customer (i.e., customer bills) would go one step further and incorporate fuel and purchase power procurement activities, much of which is now insulated by fuel adjustment clauses.*

The administrative regulatory costs associated with the remaining performance criteria, load/forecast and efficiency measures, may be lower than these for either of the first two approaches, if the data and necessary adjustments are already subject to regulatory proceedings.

3.106 Cost Minimization

Do any of the performance criteria create the desirable incentive to minimize the cost of delivering supply or demand-side options?

Most rate-of-return plans, either proposed or in effect, incorporate separate mechanisms to recover direct DSM program costs. These DSM cost recovery mechanisms generally rely on regulatory oversight and the accompanying risk of disallowance to assure that program costs are reasonable. If this is the case, none of the four performance criteria in Table 1 (with the possible exception of the fourth-- Efficiency Measure) provide any incentive to minimize the cost of efficiency improvements.

On the other hand, if the rate-of-return adjustment and the resulting payment to the utility includes program cost-recovery, a substantial incentive to minimize the cost of delivering energy efficiency exists. In this case, the utility's financial reward would increase if its cost to achieve any particular result were lower. The utility would be better off if it reached or surpassed a performance goal and at the lowest possible cost.[61]

3.11 Rate-of-Return Adjustment -- On DSM Investment

3.110 General Description

This approach assumes that a state permits or requires ratebasing of DSM investments. In other respects this approach is very similar to the rate-of-return adjustment on total investment, except that the increased rate-of-return is applied only to investments in conservation or load management activities.

The performance criteria shown across the top of Table 2 are the same criteria used in the discussion of return adjustments to total investment. The criteria are as follows:

(1) Estimated Savings - DSM impact on an estimated basis.
(2) Actual Savings - DSM impact on an actual basis.
(3) Load vs.Forecast - DSM impact as measured by actual demand for electricity vs. the adjusted load forecast.
(4) Efficiency Measure - DSM impact based on an efficiency measure.

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[61] *See Appendix A Section A.2 for a discussion of ways to minimize or eliminate the cream-skimming incentive.*

TABLE 2

RATE-OF-RETURN ADJUSTMENTS
(On DSM Investment Only)

PERFORMANCE CRITERIA	(1) Estimated Savings	(2) Actual Savings	(3) Load vs. Forecast Difference	(4) Efficiency Measure BTU/$GNP KWH/Customer
DSM INCENTIVES	*Perverse*	*Good direction but inadequate*	*Good direction but inadequate*	*Good direction but inadequate*
DECOUPLING	*No*	*No*	*No-Inadequate revenues*	*No-Inadequate revenues*
SCOPE	*DSM Only*	*DSM Only*	*DSM Only*	*DSM and partial supply-side with certain efficiency measures*
COST MINIMIZATION	*Perverse*	*Perverse*	*Perverse*	*Perverse except with certain measures*
ADMINISTRATIVE SIMPLICITY/COST	*Low cost*	*Low incremental cost if good program evaluation is done*	*Medium to low*	*Medium to low*

3.111 Incentive Potential

The potential of this approach to produce revenues necessary to offset existing disincentives is very limited. The following table shows that the level of DSM investments is so low in relation to the magnitude of the existing disincentives that plausible adjustments to the rate of return have no practical effect.

DSM COSTS AND RETURN[62]

Lost Revenue	$.05/KWH
Incremental Investment in DSM	$.10/KWH
Incremental Return at:	
12%	$0.012/KWH
14%	$0.014/KWH
20%	$0.02/KWH
Required Overall Return on DSM Investment to Produce $.05	50%
Required Equity Return on DSM Investment to Produce $.05	100%

This table shows that the incremental earnings produced by typical ratebasing incentive plans are a tiny fraction of what would be required to change the overall financial incentives. Consequently, this approach is only useful when combined with other cost recovery and decoupling options.

3.112 DSM Incentives

DSM incentives are, once again, perverse if based upon estimated determination of DSM impacts.

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[62] *Direct DSM program costs are fully recovered through annual amortization or depreciation charges and, therefore, not shown on this table.*

The incentives are generally positive for the remaining performance criteria (actual measurements, changes in load growth, or changes in efficiency). Utility earnings increase as actual performance improves; however, because utility earnings would be directly proportional to the amount of DSM investment, cost minimization would be discouraged.

3.113 Decoupling

Neither the first nor the second performance criteria achieve decoupling. Theoretically, the third and fourth criteria can decouple profits from sales. Under both of these variations (change in load growth and change in efficiency), increased sales would tend to reduce the utility's incentive payment. The increased sales, however, would produce far more earnings than would be lost through a lower incentive payment.

Thus, because the earnings potential of these criteria is so small, as a practical matter decoupling would not likely be accomplished.

3.114 Scope

As was the case with rate-of-return adjustments applied to total investment, none of the first three performance criteria is capable of extending efficiency opportunities to the supply side. Depending on the particular efficiency measure selected, the fourth criterion may capture some supply-side efficiency improvements.

3.115 Administrative Simplicity

The conclusions discussed at Section 3.105 is equally applicable here.

3.116 Cost Minimization

Because this approach would relate the level of the incentive payment to the level of DSM investment, the utility's financial interest would be best served by pursuing the more costly DSM opportunities. The incentive to minimize DSM costs would be the same as the incentive to minimize the cost of any investment, i.e., the risk of detection by regulators and the possible disallowance of costs.

3.12 Rate-of-Return Adjustment -- Customer Bills

3.120 General Description

This approach adjusts a utility's rate of return (on total investment) in relation to performance criteria which focus on customer bills. In part, this approach is being treated separately to illustrate some of the different measurement approaches available and the effect of the choices on the resulting incentives.

There are at least four different ways to specify performance criteria, each of which produces a different set of overall incentives.[63] The performance criteria shown in Table 3 are as follows:

(1) Forecast vs.Actual - This performance criterion compares actual average customer bills (by customer class) to prior forecasts of customer bills. The forecast would be consistent with the average bills after implementing a reasonable LCP, and adjusted for factors which are outside of the utility's control, such as economic and weather conditions.

(2) Internal Index - The next criterion is similar to a comparison of average bills for participants with those of non-participants. A statistically valid sample of utility customers would be selected and their future participation in DSM programs monitored. Customers in the sample group who elect to participate in programs during the next year (or two) would be dropped from the sample or control group. The control group would provide an "internal index" against which all other average customer bills would be compared. The utility would be rewarded or punished based on differences between the average bills of customers in the internal index and bills of customers overall.

(3) External Index - This performance criterion begins with average customer bills for a targeted utility and average customer bills for a group, or index, of other utilities, which in the aggregate have the same fuel mix, weather, and economic conditions as the targeted utility. The targeted utility's allowed rate of return would be adjusted up or down depending on relative changes in the average customer bills for the targeted utility compared to the average customer bills of the index. Thus, if customer bills for the targeted utility increase over a relevant time period by 10%, while bills increase by 12% for the index, the utility would have outperformed the index group and would have a higher rate of return based on the two percentage point differential.[64]

(4) Before/After - The final performance criterion focuses on the difference in customer bills prior to and following participation in the program. The difference in bills would be adjusted for variations in weather conditions and other factors which would have substantially affected bills but are unrelated to the utility's DSM program.

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[63] *Throughout this discussion, "average customer bills" refers to average bills for a customer class. Thus, average residential bills would be equal to total residential revenue divided by total number of customers.*

[64] *For a more complete discussion of this approach see Moskovitz and Parker, "How to Change the Focus of Regulation so as to Reconcile the Private Interest With the Public Goals of Least-cost-Planning" (Presented to NARUC's Sixth Biennial Regulatory Information Conference, September,1988).*

TABLE 3

RATE-OF-RETURN ADJUSTMENTS
(Customer Bills)

PERFORMANCE CRITERIA	(1) Forecast vs. Actual	(2) Internal Index	(3) External Index	(4) Before vs. After
DSM INCENTIVE	*Good*	*Good*	*Good*	*Good*
DECOUPLING	*Yes*	*No-But can offset lost revenues*	*Yes*	*Partial*
SCOPE	*Full coverage except for forecast adjustment*	*DSM Only*	*Full coverage*	*Full coverage except for adjustments*
COST MINIMIZATION	*Yes*	*No-Unless payment includes cost recovery*	*Yes*	*Partial*
ADMINISTRATIVE SIMPLICITY/COST	*Medium*	*Medium*	*Medium*	*Medium*

3.121 Incentive Potential

Because these plans all operate by adjusting a utility's rate of return on overall investment, the incentive potential is the same as rate-of-return adjustments on total rate base. (See Section 3.1)

3.122 DSM Incentive

Because all of the approaches are designed to capture actual savings, they each produce reasonable incentives to pursue DSM activities . In each case more, or lower-cost, DSM will produce greater incentive payments.

3.123 Decoupling

In both the first (target/actual) and third (external index) criteria, sales promotion to existing customers would negatively impact the utility's measured performance, but would not affect the yardstick against which that performance is compared.[65] Thus, increased sales produce lower or negative incentives. This condition means the first and third criteria can decouple profits from sales.

For the internal index and before/after criteria, increased sales would affect both the yardstick and the utility's measured performance, and there would be no net effect on the incentive measure.[66] These criteria are therefore, not capable of decoupling profits from sales.

3.124 Scope

The first (forecast/actual), third (external index), and fourth (before/after) criteria would credit a utility's performance with all actions which reduce average bills in relation to the yardstick. Because bills are reduced by cost-effective demand-side measures and cost effective supply-side measures (or any cost-cutting opportunities the utility may have), these approaches can provide a wide range of desirable incentives. For example, forecasted average bills would include an assumption about the cost of new power acquisitions which would become the yardstick against which actual performance is measured. Utility power acquisition that is less costly than forecast will increase the utility's incentive payment.[67]

Supply-side decisions affect the yardstick in the second approach (internal index) to the same extent they affect the utility's measured performance. Therefore, this variation is limited to DSM programs.

3.125 Administrative Simplicity

All the criteria are reasonably easy to administer. The first (actual vs. forecast) and fourth (before/after) may involve more substantial regulatory proceedings to determine the scope and impact of any required adjustments. The second (internal index) and third (external index) would require less effort after the system is established, but more effort initially to create a reasonable index.

3.126 Cost Minimization

Approaches which include the cost of DSM programs in average bills, but which are not included in the yardstick, would provide incentives to minimize the cost of the programs.

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[65] *The addition of new low-use customers would decrease average bills and the addition of new high-use customers would increase bills. As utilities have relatively little influence over their number of customers, the best a utility could realistically do is encourage all new customers to be as efficient as possible.*

[66] *In the fourth approach (before/after), there may be a partial decoupling, but only to the extent that the increased sales affect the group of participating customers.*

[67] *With respect to the first (forecast/actual) and fourth (before/after) approaches, the scope of the program is limited only by those matters taken into account to adjust the forecasted bills. Thus, if forecasted bills are adjusted to reflect actual purchases from qualified facilities, this element would be eliminated from the scope of the incentive plan.*

Thus, the first (forecast/actual) and third (external index) criteria would automatically provide an incentive to establish DSM programs at the lowest possible cost. In fact, with both criteria, if the cost of DSM programs exceeds the utility's avoided cost, average customer bills would increase and the utility would be penalized or at least receive no reward.

In the ordinary case, the second criterion (internal index) would not provide an incentive to minimize cost because the cost of DSM programs is borne by both participants and non-participants alike. Because the cost would be included in the average bills of the control group and all other customers, there would be no apparent change in bills and, therefore, no incentive to minimize the cost of DSM programs.

The fourth criterion (before/after) would provide a partial incentive to minimize cost because bills measured before a DSM program would not reflect the program cost, while the bills measured after program implementation would ordinarily reflect DSM program costs. The incentive is limited, however, because bill calculation will reflect only those costs which have been allocated to the participating customer class.[68]

3.2 SHARED SAVINGS

3.20 General Description

In the broadest sense, all incentive plans may be considered shared savings plans. Different approaches (e.g., rate-of- return adjustments, bounty, etc.) use different mechanisms to identify and split available savings, but no approach produces payments to utilities which exceed total savings. This section, however, considers only those incentive plans which explicitly identify a savings and propose a sharing mechanism to compensate utilities for all, or part, of the direct and indirect costs incurred from an energy efficiency improvement.[69]

Table 4 summarizes the incentives associated with the following four variations of shared savings plans:

(1) Resource Savings - Estimated - Shared savings proposals can be divided into two categories, depending on the savings being shared. This approach identifies a net resource savings as the difference between avoided cost and

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[68] *The incentive would not be limited if the before/after calculation was adjusted solely for the purpose of determining the level of an incentive payment by allocating all DSM program costs to participating customers.*

[69] *For examples of this approach see Wellinghoff, "The Forgotten Factor in Least-Cost Utility Planning: Cost Recovery," P.U.F., March 31, 1988; and "Inquiry of a Ratemaking Methodology for Encouraging Demand-Side Resource Options, Finding and Conclusions," Docket No. 89-651, Nevada Public Service Commission, July 6, 1989.*

the cost of an energy efficiency improvement.[70] The net savings is then split between the utility and the consumer. To distinguish this approach from others, it will be referred to as "shared resource savings." In this first performance criterion, the DSM savings are estimated.

(2) Resource Savings - Actual - The second variation is the same as the first except DSM savings are based on actual measurements.

(3) Bill Savings - This approach is similar to the model of third-party energy service companies that identify reductions in customer bills after an energy efficiency improvement. The savings are then split between the efficiency provider and the customer. The provider's share normally covers the installed cost of the efficiency improvement. This approach will be referred to as "shared bill savings."

(4) Unbundled Energy Services - Finally, proposed approaches exist, which in various ways, unbundle energy-supply and energy-savings services. These approaches "buy" or "sell" cost-effective energy conservation services from or to customers. In one variation, the utility (or contractor) installs a demand-side measure and charges the customer for the saved KWHs. The charge for KWHs is equal to the utility's retail rate. For example, the utility may either sell extra KWHs to power an uninsulated electric water heater or sell fewer KWHs plus the energy service of insulating the water heater. If the water heater insulation blanket saves 600 KWHs per year, the utility charges the

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[70] *Some approaches define this difference in more detail than others. For example, the Nevada Notice of Inquiry provides:*

> *"Net System Benefits are the reduction in revenue requirements resulting from the implementation of demand-side programs. Such benefits are described by the Utility Cost Test contained in Chapter 5 of the California Standard Practice Manual... After removing the present value (discount and summation) terms and alternate fuel terms (which would apply to another utility) the formula becomes:*
>
> $$\underset{[\text{Net System Benefits}]}{NSB} = \underset{[\text{Benefits}]}{[\ UAC\ ]} - \underset{[\text{Costs}]}{[\ UC + INC + UIC\ ]}$$
>
> *A sharing fraction g would be determined to allocate the savings between the utility and its customers such that the demand-side incentive (DSI) would be:*
>
> $$DSI = g(NSB), \text{ where: } 0 < g > 1$$
>
> *The sharing fraction would be set at the sole discretion of the Commission at the time of its preapproval of capitalizing the applicable demand-side program(s). At a rate case proceeding, the net system benefits accrued since the previous rate case would be allocated."*

customer the full retail rate for the saved energy.[71]

Another, and very similar, approach exists which incorporates demand-side bidding procedures into a qualifying facility and supply-side action. In this approach the retail customers or a third-party energy service company could bid to deliver demand-side measures on the same basis as a supply-side proposal, but the bidder would pay the utility for saved KW and KWH at the full retail rate.[72]

Appendix B includes a discussion of the comparison of unbundled bidding plans to shared bill plans. The discussion concludes that unbundled energy plans are essentially shared bill savings plans in which most savings are retained by the utility.

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[71] *Whittaker. "Conservation and Unregulated Utility Profits: Redefining the Conservation Market," Public Utilities Fortnightly, July 7, 1988; and Katz. "Proper Utility Incentives: Everybody Wins," presented at Western Conference of Public Utility Commissioners, June, 1989.*

[72] *See Cicchetti and Hogan. "Including Unbundled Demand-Side Options in Electric Utility Bidding Programs," Public Utilities Fortnightly, June 8, 1989.*

TABLE 4

SHARED SAVINGS

PERFORMANCE CRITERIA	**(1) Resource Savings Estimated**	**(2) Resource Savings Actual**	**(3) Bill Savings****	**(4) Unbundled Energy Services**
DSM INCENTIVE	*Perverse and inadequate*	*Good, but inadequate*	*Good*	*Good*
DECOUPLING	*No*	*No*	*Depends on measurement (see Table 3)*	*No-But offsets lost revenues*
SCOPE	*DSM and possibly new supply*	*DSM and possibly new supply*	*DSM*	*DSM only*
COST MINIMIZATION	*No-Unless payment includes cost recovery*	*No-Unless payment includes cost recovery*	*Maybe, See Table 3*	*Yes*
ADMINISTRATIVE SIMPLICITY/COST	*Low cost*	*Low cost if data is already produced for program evaluation, otherwise Medium*	*Low market penetration, Medium cost*	*Difficult to understand, Medium cost*

***The measurement variations in Table 3 apply with equal force to shared bill savings.*

3.21 Incentive Potential

Some, but not all, of the shared savings plans can produce enough incremental earnings to offset existing financial disincentives. For example, in shared resource plans, the savings (Savings = Avoided Cost - DSM Cost) available to be shared approaches zero as the DSM cost approaches full avoided cost. This is why incentive plans which incorporate shared resource concepts are combined with other cost recovery and decoupling approaches.[73]

The savings available from a bill savings plan can be large enough to offset lost revenues and DSM costs. For example, using the typical utility data shown in Section 3.0, the bill savings to the participating customers would be \$.07 per KWH. This savings would be adequate, albeit barely, to compensate the utility for a \$.05 non-fuel revenue loss, plus the \$.02 cost of conservation. In addition, a further \$.01 net savings associated with fuel costs (the difference between the \$.02 average and \$.03 marginal fuel cost) would result which, under ordinary circumstances, would be shared by all customers.[74]

3.22 DSM Incentives

Table 4 summarizes the incentive structure of various shared savings approaches. Like other incentive plans, shared savings plans which rely upon estimated savings produce the wrong incentives. Under this variation, superior results will yield lower earnings and vice versa.

Either the shared resource or bill savings approach can yield reasonable incentives if the savings to be shared are based on actual achievements.[75]

3.23 Decoupling

The extent of decoupling depends on the specific performance criteria. For example, if bill savings are identified using either before/after or participant/non-participant comparisons, the incentive to increase sales is largely unaffected, and decoupling is not achieved. On the other hand, measuring shared bill savings by the target/actual or external index approaches can decouple profits from sales.[76]

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[73] *For example, the preferred approach in Nevada correctly combines a shared resource savings approach with DSM cost recovery and a mechanism to restore lost revenues. Likewise, New York has recently approved temporary incentive plans for Niagara Mohawk and Orange and Rockland, which combine a shared revenue approach with DSM cost recovery and lost revenue recovery.*

[74] *The \$.01 fuel savings is not available for use in a shared savings plan because it is shared by all customers.*

[75] *By the nature of the plan, bill sharing approaches tend to be ex post or actual measurements.*

[76] *Measuring on this basis is more amenable to plans that focus on average bills for large groups of customers, as opposed to plans that are limited to customer specific bill savings. See Geller, "Use of Financial Incentives to Encourage LCUP and Energy Efficiency," June 1988, for a fuller discussion of the target/actual*

Shared resource savings approaches do not result in decoupling. Consequently, this approach will produce the desired incentives only if it is combined with other plans which decouple profits from sales.

3.24 Scope

The shared resource savings approaches proposed have focused only on demand-side measures. There is no reason, however, why supply-side resource saving cannot be measured and shared in a similar fashion.

The efficiency of supply-side decisions is ultimately reflected in customer bills. Therefore, depending on the precise performance criteria selected (see Table 3), bill sharing plans can capture efficiency gains for both demand- and supply-side resources.

3.25 Administrative Simplicity

Resource savings approaches require the measurement of avoided costs, as well as the cost and quantity of capacity and energy saved by efficiency programs. As a general matter, commissions and utilities already calculate avoided costs for other purposes and therefore will not need to undertake complicated administrative requirements. Deriving program-by-program savings estimates will require significant effort unless the data is already gathered for DSM program evaluation or other purposes.[77]

Different measurement issues are raised for a shared bill approach. The principal information required to conduct a shared bill plan is readily available customer billing information. Additionally, methods of identifying changes in customer bills such as before/after or participant/nonparticipant comparisons must be developed.

The unbundled approaches involve measurement issues similar to those of shared bill plans. However, unbundled plans raise serious questions of public understanding and customer acceptance. For example, it is unlikely that any but the most sophisticated customers will accept plans which require the participating customer to continue paying for saved KWHs.

3.26 Cost Minimization

Some variations of shared savings approaches can provide incentives for utilities to maximize net savings and to obtain efficiency or other resources at the lowest possible cost.

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approach. Also, see Section 3.12 for additional discussion of the difference between the various bill savings measurement approaches.

[77] *While a shared resource savings approach could be administered on a program-by-program basis, the same result would occur if measured on an aggregate basis. Measuring aggregate program impacts may pose fewer problems than attempting to disaggregate to the program level.*

Shared resource savings approaches which include DSM program cost-recovery as part of the utility's share of the savings will provide an incentive to achieve savings at the lowest possible cost. If DSM program costs are recovered through separate ratemaking procedures, the plan itself will not provide a financial incentive to be cost effective and other procedures must be used.[78]

Shared bill savings approaches ordinarily include DSM program cost recovery as part of the utility's or ESCO's savings share. Therefore, these approaches provide a financial incentive to minimize the cost of DSM programs.[79]

3.27 Non-Participant Impacts

The ability of different incentive approaches to create incentives to minimize non-participant impacts is discussed in Appendix A. It is also noted here because two of the shared savings approaches, shared bill savings and unbundled energy services, are designed to eliminate non-participant impacts. In the ordinary form of both of these variations, all of the DSM program's direct and indirect costs are borne by the participating customers and there are, consequently, no non-participant impacts.

3.3 BOUNTY

3.30 General Description

Bounty approaches provides payment, i.e. a bounty, to utilities in return for specified achievements. For example, a utility might be paid a bounty of "x" cents for each KWH saved, or "y" dollars for each block of power saved.[80]

Table 5 summarizes the incentives produced by five different performance criteria for bounty plans. Any of the criteria can be implemented based on bounty per KWH, KW, or a combination of the two. The performance criteria are as follows:

(1) Estimated Savings - In the first criterion, DSM impacts are based on estimated savings determined prior to program implementation. A bounty, or payment, is made to the utility for each KW or KWH of estimated savings.

(2) Actual Savings - The next criterion measures DSM program impacts

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[78] *The incentives to deliver lowest-cost DSM programs will be determined by the characteristics of the separate cost-recovery mechanism, not the shared savings plan.*

[79] *The specific incentives, however, depend on the way bill savings are measured. The conclusions contained in the discussion of "Rate-of-Return Adjustment - Customer Bills," apply with equal force here.*

[80] *The payment is always less than avoided cost; thus, this approach can also be considered a shared savings plan.*

after the fact to identify actual results.

(3) Single Price - This criterion is a particular variation of (2) in which the bounty is a single fixed payment for each KWH saved. Thus, if a bounty is established at $.02 per KWH saved, $.02 would be paid whether the KWH were saved by a lighting program, an insulation program, or a motor replacement program.

(4) Multiple Price - This criterion is another variation of (2), but different prices are set for different programs. The bounty amount depends upon the type and cost of the program and its on-peak/off-peak resource-savings characteristics.

(5) Load vs.Forecast - The last criterion shown in Table 5 pays the utility based on achieved savings measured by comparing actual power demands to previously forecast demands adjusted for major variables such as weather and economic conditions (target/actual).

TABLE 5

BOUNTY

PERFORMANCE CRITERIA	(1) Estimated Savings	(2) Actual Savings	(3) Single Price	(4) Multiple Price	(5) Load vs. Fore-Cast
DSM INCENTIVE	*Perverse*	*Good, but insufficient*	*Good, but insufficient*	*Good, but insufficient*	*Good, but insufficient*
DECOUPLING	*No*	*No*	*No*	*No*	*Yes*
SCOPE	*DSM and possibly supply*	*DSM and possibly supply*	*DSM and possibly supply*	*DSM and possibly supply*	*DSM only*
COST MINIMIZATION	*No-Unless bounty includes program cost recovery*	*No-Unless bounty includes program cost recovery*	*Yes-But risk of cream skimming*	*Yes*	*No-Unless bounty include program cost recovery*
ADMINISTRATIVE SIMPLICITY/COST	*Low cost*	*Medium cost*	*Medium cost*	*High cost*	*Medium cost*

3.31 Incentive Potential

Bounty payments are ordinarily limited to full avoided cost and, therefore, can compensate utilities for only direct DSM costs which, at the extreme, are equal to avoided costs. Consequently, bounty plans must be combined with other cost recovery and decoupling options to be fully effective.

3.32 DSM Incentives

As was the case for all of the other incentive criteria, basing the incentive payment on estimated results produces perverse incentives. Alternatively, the incentives are reasonably good for bounty programs when performance criteria based on actual program achievements are measured on a program-by-program or aggregate basis.

The principal difference between the single price and multiple price variations in bounty plans (both assumed to be measured with actual figures) is that the single price plan will provide the greatest incentives to obtain the lowest cost efficiency opportunities.

In the multiple price plan, bounty prices would be set lower for low cost savings and higher for high cost efficiency opportunities. Generally, the different bounties would be priced to produce the same level of incentives to pursue cost effective DSM opportunities, regardless of the cost of the opportunity.[81]

For the fifth criterion (target/actual), the utility would have an incentive to achieve the greatest possible savings.

3.33 Decoupling

In each of the first four variations (estimated, actual, single price, multiple price), increased sales, regardless of the cause, have no effect on the apparent success in meeting a performance measure. Therefore, none of these criteria decouple profits from sales.

The fifth criterion (target/actual) can at least partially decouple because increased sales lead to a higher level of actual load, which reduces the bounty paid to the utility. This characteristic can be used to decouple profits completely from sales, but only if the level of the bounty is adequate.[82]

3.34 Scope

While bounty plans have been implemented or discussed only in conjunction with demand-side programs, there is no theoretical reason why these criteria cannot be applied to supply-side resources. A bounty can be offered for each MW of cost effective capacity, each MW of a renewable resource, or each MW of an environmentally benign source.

3.35 Administrative Simplicity

Administrative costs are the highest with the fourth criteria (multiple prices), due to the need to track separate program savings and incentive payments.

3.37 Cost Minimization

The bounty criteria provides the impetus to minimize delivered efficiency improvement costs only if the bounty payments include compensation for DSM program expenditures.

3.4 DECOUPLING

3.40 General Description

Breaking the link between profits and sales is an important step towards correcting the current regulatory system's incentives.

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[81] *This discussion of the distinction between single- and multiple-price bounty plans assumes that the bounty payment includes the utility's program cost recovery. If a utility's program cost are recovered in another fashion, then the single price approach will provide an equal incentive, regardless of the direct program cost.*

[82] *The extent of decoupling depends on the difference between the added earnings from increased sales and the earnings reduction due to lower measured load reductions.*

Some variations of the three general incentive plan categories involve performance measures that tie incentive payments to sales levels. In these instances, the utility is not explicitly made whole.[83] Instead, higher sales lead to a smaller or even negative incentive and lower sales lead to greater incentive. Decoupling profits from sales is accomplished when the incremental earnings from increased sales is equal to or less than the incremental reduction in earnings produced by the incentive plan. Many of the plans discussed and described in the tables, however, cannot decouple profits from sales. Nevertheless, these plans can be used if combined with separate regulatory reforms which decouple. Indeed, any of the plans described, even those capable of decoupling, can be combined with separate decoupling approaches. In that case, the need for the incentive plan would be significantly reduced.

3.41 Electric Revenue Adjustment Mechanism (ERAM)

In 1978, the California Public Utilities Commission adopted the Electric Revenue Adjustment Mechanism (ERAM). At the time of a rate case, the California Commission, using a future test year approach, established the utility's non-fuel revenue requirement. ERAM uses the revenue limit established in the rate case and, on a going-forward basis, tracks non-fuel revenue as it is received by the utility from customers. To the extent that actual annual non-fuel revenue collected by the utility deviates from the allowed revenue, the company either surcharges or refunds ratepayers.[84]

If sales and, therefore, revenues are lower than expected, the revenue shortfall is returned to the utility though a rate adjustment. If sales and, therefore, revenues are higher than expected, the utility must return the over-collection to customers. These adjustments are made regardless of the cause of the revenue difference.[85] Since 1978, ERAM has produced ratepayer refunds about as often as it has produced utility surcharges.

The important difference between ERAM and approaches which restore DSM-induced lost revenue is the different treatment of revenue from increased sales. This is the ERAM element that removes the profits from increased sales.

Finally, because ERAM operates on an overall revenue level, measurement of energy efficiency is not required. The only measurement requirements, namely revenues, are straightforward and easily verifiable.

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[83] *California's ERAM is an example of an effective decoupling approach which does operate as a make-whole mechanism.*

[84] *Because revenues are fixed and not earnings or profits, the incentive to cut costs and thereby increase the level of earnings remains unchanged.*

[85] *Besides conservation, the major factors that affect sales and revenue levels are weather and economic conditions. While making utility revenues indifferent to sales, ERAM also makes utilities indifferent to weather and general economic conditions. Because neither weather nor economic conditions are within the utilities' control, little is lost by removing the risks from utilities.*

3.42 ERAM on a Per-Customer Basis

Because ERAM fixes revenue requirements for a future period, it requires a forecast of all rate case components that will influence the utilities' future revenue requirements. This means ERAM, as implemented in California, fits well only with states using a future test year approach to rate-making or an historic test year supplemented with attrition analysis.[86]

A variation on the California ERAM exists, which can be implemented in states using either historic or future test year. At the time of a rate case, revenue requirement is divided by the corresponding number of customers (by customer class). This produces a revenue-per-customer limit which would then operate like ERAM. While new rates are in effect, the utility tracks non-fuel revenues received from customers, as well as the number of customers. Rates are adjusted annually so the utility retains only the allowed non-fuel revenue per customer.

The theory behind setting rates on an historic test year basis is that the test year establishes a constant relationship between costs, investments, and revenues. Increased revenues, realized in the period during which rates are to be in effect, are supposed to offset higher costs incurred after the test year and no more. In fact, in the short term, increased sales to existing customers do not produce increased non-fuel related costs.

Using a revenue-per-customer approach is a practical way to reconcile the realities of utility economics with the theoretical basis of historic test year ratemaking. This approach allows utilities to retain incremental revenues associated with higher sales due to changes in the number of customers. Because new customers often mean new non-fuel related costs, including poles, wire, meters and capacity, this modification tends to reduce earnings erosion that would occur if a strict revenue cap were imposed. Meanwhile, increased revenue (net of fuel costs) that results from increased sales to existing customers would be returned to customers instead of increasing utility earnings.

3.43 Fuel Revenue Accounting

An approach implemented in Maine in 1986 can be used to decouple profits from sales in states with a reconciled fuel adjustment clause.

Most states with a reconciled fuel adjustment clause either explicitly or implicitly allocate average fuel cost to each KWH sold. Thus, a \$.07 commercial rate and a \$.05 industrial rate each include \$.02 of average fuel cost. This means that the non-fuel contribution to earnings is \$.05 for the commercial rate and \$.03 for the industrial rate (rate minus average fuel cost).

Similarly, for a utility with time-of-use or seasonal rates, the higher on-peak rates make a greater contribution to profits. For example, a utility may have a \$.10 per KWH on-peak rate and a $.05 per KWH off-peak rate. In most states, both prices include an average fuel cost of $.02. This means the non-fuel component of the on-peak rate is $.08 and only $.03 for the off-peak rate. On-peak sales, therefore, add substantially more to earnings than off-peak sales, and a utility able to shift load from off-peak to on-peak periods realizes higher, not lower, profits.[87] This is exactly the opposite of what regulators would like to have happen. Of course, the more likely response to these incentives is that the utility would not actively encourage or assist customers in shifting on-peak load to off-peak periods.

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[86] *An attrition analysis also requires forecasted sales and expense levels and is, therefore, amenable to a California ERAM approach.*

These issues, along with decoupling profits from sales, can be addressed by changing the accounting treatment of fuel and non-fuel revenues.[88] Rather than account for all fuel revenues on a flat average per KWH basis, a greater proportion of on-peak (or tail-block) prices can be treated as fuel revenue, leaving a smaller portion of on-peak (or tail-block) rates to contribute to earnings.[89]

The following table illustrates the changes in accounting using the previous example of a utility with time-of-use prices.

	ON-PEAK	OFF-PEAK
BEFORE		
Fuel (cents/KWH)	$.02	$.02
Non-Fuel (cents/KWH)	$.08	$.03
Price (cents/KWH)	$.10	$.05
AFTER		
Fuel (cents/KWH)	$.08	$.01
Non-Fuel (cents/KWH)	$.02	$.04
Price (cents/KWH)	$.10	$.05

This table points out three important features of fuel revenue accounting:

- Prices are unchanged by the accounting change. Rate design questions do not arise from such an approach.
- Shifting consumption from on-peak to off-peak previously cost the utility $.05 in lower earnings. After the accounting change, utility earnings would increase by $.02.

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[87] *Boston Edison recently implemented time-of-use rates which resulted in customers shifting load from on-peak to off-peak periods. The difference between on-peak and off-peak contribution to earnings meant Boston Edison experienced a significant drop in its earnings.*

[88] *Changing the accounting treatment does not require any change to actual retail prices. The accounting changes are invisible at the customer level but very visible to the utility.*

[89] *A utility's price structure might charge $.05 per KWH for the first 300 KWH's and $.06 per KWH for all additional KWHs. The $.06 portion of the price structure is called the tail-block.*

- **Increased on-peak sales used to be very profitable. After the change, increased on-peak sales may not be profitable at all.**[90]

The same approach can be used for rates without time-of-use or block features. For these rates, new "accounting blocks" can be created that accomplish the same result. For example, a flat $.07 per KWH residential rate can be turned into a two-block rate schedule. The first 300 KWH would be billed to customers at $.07 per KWH but accounted for as $.05 non-fuel revenue and $.02 of fuel revenue. Sales in excess of 300 KWH would also be billed to customers at $.07 per KWH but accounted for as $.02 non-fuel and $.05 fuel.

These changes are illustrated in the following table:

	FIRST 300 KWH	EXCESS SALES
BEFORE		
Fuel (cents/KWH)	$.02	$.02
Non-Fuel (cents/KWH)	$.05	$.05
Price (cents/KWH)	$.07	$.07
AFTER		
Fuel (cents/KWH)	$.02	$.05
Non-Fuel (cents/KWH)	$.05	$.02
Price (cents/KWH)	$.07	$.07

Making these changes in the accounting treatment of fuel substantially reduces and possibly eliminates the non-fuel contribution of the marginal KWHs sold. Decoupling is accomplished when incremental sales add only that revenue needed to offset incremental costs.[91] Meanwhile, in all other respects the fuel clause mechanism remains intact. During each fuel clause period, an effort is made to match fuel costs with fuel revenues, and any differences are made up in subsequent periods.

3.44 Fuel Clause Reform

Another approach for states with fully reconciled fuel adjustment clauses is to eliminate or reduce the extent or scope of reconciliation. Abolishing the reconciliation features of a fuel adjustment clause would mean that incremental revenues from increased sales would be at least partially offset by incremental fuel costs. Conversely, saving a KWH would produce cost savings equal to the marginal cost of fuel. This cost savings would at least partially offset the revenue lost by foregoing a sales opportunity. Incremental sales would continue to add to earnings, but only to the extent that the marginal price of electricity exceeds the marginal fuel cost of producing the electricity.[92]

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[90] *If the $.08 fuel revenue attributed to the on-peak KWH sales exceeds the actual marginal fuel costs, the difference would be returned to customers because of the fuel clause reconciliation provisions. This reimbursement to customers would further reduce the on-peak contribution to earnings below the apparent $.02 level.*

[91] *In addition to decoupling of profits from sales, this approach tends to level utility earnings over the course of a year, thereby reducing earnings volatility and reducing earnings sensitivity to weather and other uncontrolled factors.*

A milder reform to accomplish a similar result would be to continue the reconciliation provisions of fuel clauses, but limit the scope of reconciliation to changes in fuel prices. For example, fuel clauses might initially be established based on projected fuel prices expressed as dollar per barrel, dollar per ton, etc. Reconciliation, or true-up, provisions would then be limited to adjustments which reflect the difference between the assumed fuel prices and actual prices. Fuel quantities, a function of plant performance and sales levels, would not be reconciled. An incremental KWH sold would increase fuel quantity without regard to what may have happened to fuel prices. Similarly, saving a KWH would reduce fuel quantity and save the utility the marginal cost of fuel used to produce the KWH.

The effect of this change on the DSM incentives would be the same as eliminating the reconciliation features entirely. This approach, however, would continue to insulate utility earnings from the volatility of fuel prices.

The attributes of these four decoupling approaches are summarized in Table 6.

TABLE 6

DECOUPLING

	ERAM	**ERAM CUSTOMER**	**FUEL ACCOUNTING**	**FUEL REFORM**
EXTENT OF DECOUPLING	*Complete*	*Complete*	*Partial to Complete*	*Partial*
LIMITATIONS	*Requires future test year*	*Future or historic test year*	*Requires reconciled fuel clause*	*Limited ability to correct incentives*

Conclusion

Table 7 presents a summary of the conclusions reached in this Section. Listed across the top of the Table are different assumptions of how state regulation of incentive plans might be structured. For example, the first column, "W/O Decoupling, W/O DSM Cost

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[92] *Currently, retail prices almost always exceed the utilities' marginal fuel cost.*

Recovery," describes a state which has not adopted ERAM or any of the other decoupling options and which has no separate DSM program cost-recovery mechanism. This means that the incentive plan selected must be capable of decoupling profits from sales and also give reasonable treatment to DSM program costs. Next, the table summarizes the capabilities of alternative incentive plans to produce a desirable result given the assumed regulatory status. A "yes" (Y) response means the incentive approach is a good candidate and attention should turn to the various ways that the general approach can be implemented. A "no" (N) response means the approach is not a good candidate and a "maybe" (M) response means the performance of the approach depends on other factors.

TABLE 7

SUMMARY
ALTERNATIVE INCENTIVE PLANS

	W/O Decoupling W/O DSM Cost Recovery	**W/Decoupling W/O DSM Cost Recovery**	**W/O Decoupling W/DSM Cost Recovery**	**With Decoupling W/DSM Cost Recovery**
Rate-of-Return Overall	*Y*	*Y*	*Y*	*Y*
Rate-of-Return DSM	*N*	*N*	*N*	*Y*
Rate-of-Return Bills	*Y*	*Y*	*Y*	*Y*
Shared Savings Resource	*N*	*M* *(See Note 2)*	*M* *(See Note 2)*	*Y*
Shared Savings Bill	*M* *(See Note 1)*	*Y*	*M*	*Y*
Bounty	*M* *(See Note 1)*	*Y*	*Y*	*Y*

Y - Yes, the approach is capable of producing the right incentives.

N - No, the approach is not capable of producing the right incentives.

M - Maybe. Under some conditions the approach can be made to produce reasonable incentives.

(Note 1: This approach can address all costs only if average fuel costs exceed marginal fuel costs, which is rarely the case. Otherwise, they are sufficient only for low-cost measures.)

(Note 2: This approach is possible only for very low-cost DSM measures and very low-cost revenues.)

All cases assume the use of actual rather than estimated savings.

APPENDIX A

There are a number of factors slightly less important than the factors discussed in Sections 2 or 3 but which should nevertheless be considered when designing or selecting an incentive plan. These items include consideration of fuel-switching, environmental externalities, minimization of non-participant impact, cream-skimming, and predictability.

A.0 Fuel Switching

Will the plan reward programs that achieve cost effective fuel switching by customers?

Instances exist in which large electricity and overall energy efficiency savings are feasible through fuel switching programs.[93] In some instances, switching may occur from electricity to natural gas, while in others, electricity is exchanged for a renewable fuel, for example, solar or wood. In either case, alternative incentive plan evaluations should consider how electric utility profits change as a result of customer fuel switching. Under the current system, electric utilities discourage fuel switching, no matter how cost effective, because it always means lower profits.[94]

All of the incentive plans described in Section 3 can accommodate fuel switching programs. However, some plans require a conscious decision to treat fuel switching programs like all other efficiency programs while others automatically reflect fuel switching electricity savings. For example, rate-of-return adjustments to either estimated or actual DSM savings would capture the savings of cost-effective fuel switching, but only if the fuel-switching programs are specifically treated as eligible DSM programs for which savings are estimated or measured. In contrast, rate-of-return adjustments based on load/forecast comparisons would automatically reward fuel-switching efforts.

A.1 Environmental Costs

Many states which have adopted LCP also attempt to incorporate environmental externalities in the planning and decision making process. Traditional utility planning has always included consideration of a utility's directly incurred environmental control costs. Thus, the cost of building and operating a sulfur dioxide scrubber is reflected in the cost of a new coal-fired power plant. Even a scrubbed coal plant, however, emits pollution whose environmental damage is not borne by the utility or reflected in its prices. In increasing numbers, states attempt to take these externalized costs and reflect them in the LCP decision process.[95]

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[93] *The availability of fuel switching as an element of a least cost plan varies from state to state. States with combined gas and electric utilities are more likely to look favorably on fuel switching as an option.*

[94] *The impact will be different for combined gas and electric utilities.*

[95] *External benefits from new power supplies, such as construction jobs, tax revenue, and backing-out foreign oil, are often given weight in investment decisions. External costs should be given as much consideration as external benefits.*

None of the general approaches to incentive plans expressly consider environmental externalities. Nevertheless, once a state has decided how to incorporate environmental concerns in its decision-making process, reflecting that decision in any of the alternative plans is not a difficult task.

To illustrate, a state might decide that its consumers and society overall would be served by imposing a 20% economic penalty for fossil fuel sources of generation when making its resource decisions. In other words, a state might decide that ratepayers and society would be better off paying 20% more for electricity, but saving the costs that higher levels of pollution would cause. Incorporating this type of decision into an incentive plan means that the utility's correct decision to select a 20% more expensive but cleaner option should not jeopardize its efforts to achieve the same earnings level it would have without the clean option selection. Thus, special attention should be paid to any incentive plan that measures performance against a standard without the same 20% environmental concern cost premium.

For example, consider a plan that focuses on the utility's relative ability to control customers' bills, as compared to an index of other companies. Adding 20% to the cost of the utility's new resource acquisitions (demand- or supply-side) would make the utility appear to be less efficient than the utility index group (assuming the other utilities have not had a similar policy imposed on their resource decisions). To make the bill comparison fair, 20% of the cost of all of the target utility's added demand-and supply-side resources should be subtracted from the utility's average bills before comparing its performance to the index.

A.2 Non-Participant Impacts

Is the proposed program designed to minimize nonparticipant impacts? Depending on the utility's average and marginal costs and the state specific mechanisms for DSM cost recovery, DSM programs may have an adverse impact on average prices, thereby raising prices and bills for customers who do not participate in DSM programs.[96]

As a general matter, the non-participant impact of even very large DSM programs is small, much smaller than the impact of supply-side options.[97] However, with the exception of the shared bill savings, unbundled approaches, and some of the customer bill approaches, incentive plans generally do not provide financial incentives to minimize non-participant impacts. Nevertheless, incentive plans can be structured to encourage utilities to design DSM programs in ways that minimize non-participant impacts. Generally, however, there are three steps to be taken which may address this concern.

First, a number of the variations of alternative plans provide an incentive to minimize the cost of energy efficiency programs. Minimizing the cost of energy efficiency will tend to minimize non-participant impacts.

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[96] *Rates for participating customers increase as well, but the DSM program causes their bills to decrease.*

[97] *For a more complete discussion of this and related issues see Cavanagh, "Responsible Power Marketing in an Increasingly Competitive Era," 5 Yale Journal on Regulation 331, 1988.*

Second, plans can be designed to provide incentives for utilities to obtain as much contribution as possible from participating customers. The greater the customer contribution toward energy efficiency, the lower any non-participant impacts. For example, rate-of-return adjustments based on average customer bills can exclude from the bill calculation any direct participant contribution. The greater the participant contribution, the larger the apparent bill savings and the larger the incentive. This approach, however, tends to undermine the level of participation in energy efficiency programs and, thus, may be counterproductive.

Finally, non-participant impacts may also be addressed by assuring that energy efficiency programs are widely available to all customers and all customer classes. Wide program availability will tend to minimize the number of non-participating customers.

A.3 Skimming the Cream

Will the proposed incentive plan encourage the utility to engage in cream-skimming programs, and, if so, how much of a concern is that practice?

Skimming the cream in this context means designing and carrying out only the lowest-cost measures while leaving behind other cost-effective opportunities for energy efficiency. The most common example occurs in new construction where cost-effective measures left out at the time of construction are prohibitively expensive to fix later.

In another example, commercial lighting retrofits might cost two cents per KWH saved, while heating and cooling improvements might cost four cents if done on the same trip, but six cents if done separately. An incentive program that paid the utility five cents for each saved KWH might cause the utility to improve the lighting and earn three cents while foregoing the four cent cooling improvement that would have netted only one cent. An incentive plan that paid the utility three cents for lighting and five cents for heating and cooling would net the utility the same one cent for both projects.[98]

The most important reason to avoid cream-skimming is that cost effective opportunities will be permanently lost and consumers will pay more than necessary for energy services.[99]

Of course, in comparison to existing regulations, a plan which suffered only from the potential for cream-skimming would be a vast improvement over the current system. Nevertheless, one should be aware of the possible problem and the available solutions, including solutions outside of an incentive plan itself. Cream-skimming potential is generally the greatest with plans which provide strong incentives to utilities to minimize the cost of energy efficiency.

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[98] *In this case one might still encounter another type of cream-skimming where the utility pursues only the easiest lighting and heating opportunities.*

[99] *In all cases, the DSM opportunities at risk are cost effective, but the payback on the less cost-effective measures is below the hurdle rate for the investing entity.*

In general, there are three ways to lessen the potential for cream-skimming. First, some level of regulatory oversight of program design can be retained to assure that cream-skimming programs are not implemented. This is the current approach, and this level of regulatory oversight could continue even with significant reforms of financial incentives associated with DSM program implementation.[100]

Second, any of the incentive plans may be implemented in a more disaggregated fashion. For example, bounty plans can be established to create different bounty levels for different types of programs. Lower bounties for relatively inexpensive conservation measures, and higher bounties for more expensive programs, would tend to minimize any financial incentive to pursue cream-skimming opportunities.

Third, plans which allow utilities to recover actual program costs separately from incentive plans tend to remove cream-skimming incentives. This approach, however, also removes the incentive to minimize program costs.

A.4 Predictability

While regulators will always maintain a wide range of discretion in rate-setting proceedings, incentive proposals that clearly lay out guidelines and expectations are likely to motivate utility managers more than alternatives that rely heavily upon the exercise of commission discretion.[101] Regardless of how responsible, consistent, and objective regulators are, suspicion will always exist between regulatory commissions and utilities.[102] Consequently, incentive proposals which rely upon the discretion of commissioners may not achieve full potential in motivating utility managers, even if the commission discretion is always exercised in a responsible manner.

Predictability does not mean that the utility should know in advance, or be guaranteed a particular level of earnings. Rather, the utility must know that a specific accomplishment will produce a particular and predetermined effect. The greater and more immediate the cause and effect, the more likely it is that the regulatory incentives will have a positive influence on utility managers. Similarly, incentives that reward promptly, rather than in the distant future, will be most effective.

Any of the incentive plans described in Section 3 can provide the needed level of predictability by assuring that the rules are clearly articulated prior to implementing the incentive plan. For example, in the rate-of-return adjustment criteria, it would be important to state in advance how much the rate of return would be adjusted for a particular level of results.

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[100] *In addition, experience with collaborative design efforts in New England suggests utilities and energy efficiency advocates can work together to design conservation programs in which cream-skimming potential is minimized.*

[101] *An extreme example of a plan that relies on commission discretion consists of a general promise by regulators that a utility will be treated generously if it successfully pursues any LCP.*

[102] *Even where there is no distrust the relatively short tenure of most commissioners -- about 4 years in the U.S. -- adds to the lack of predictability of approaches that rely on commission discretion.*

With respect to measurement related issues, establishing measurement criteria in advance is all that is required. For example, a plan could require program savings to be measured by randomly testing and sub-metering a sample of 2% of the installations per year. Indeed, going further and specifying that each installation will be assumed to save "x" KWH is counterproductive.

A.5 Avoid Gaming

Any regulatory system, including traditional utility regulation, is subject to efforts by parties to engage in short-term "gaming." Simple manipulations, like the timing of rate case filings, or the timing of certain maintenance expenses (such as plant maintenance or tree trimming) which can be deferred or accelerated, can all have a significant effect on the utility's bottom line. Care should be taken when selecting and designing regulatory proposals so that the opportunity for gaming is no greater than it is already.

One way to lessen the incentive for manipulation is to assure that the implemented plan will remain in effect long enough to make such gaming risky. In addition, short term gaming temptations would be minimized by allowing the capitalization and amortization of DSM program costs in a way that bears some relationship to program benefits. A recent study by the Alliance to Save Energy includes an excellent discussion of this issue.[103]

A.6 Distribution of Incentives

The effectiveness of economic incentives is a function of where the incentives are directed within the utility company, i.e., shareholders, managers, employees, etc. The implementation of regulatory incentives which serve to benefit only distant stockholders will not be as effective as regulatory incentives which are at least in part directed toward utility executives and managers responsible for the successful (or unsuccessful) implementation of the least-cost plan.

Many utilities already have incentive compensation plans in effect. These plans may not be consistent with LCP incentive plans. For example, a compensation plan that weds the salary of a plant manager to heat rate may be compatible with LCP while a compensation plan tied to sales levels would not.[104]

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[103] *"Ratebasing of Conservation Program Costs", The Alliance to Save Energy, Discussion Paper, Washington, D.C., November, 1987.*

[104] *Central Maine Power Company has instituted a management compensation plan which rewards top managers based on CMP's rates relative to other New England utilities and the level of the company's earnings per share. By selecting relative rates instead of bills, managers' salaries go up if there is little or no conservation and salaries go down if the company succeeds in implementing substantial amounts of cost-effective efficiency. The same is true for earnings per share. Earnings will go up if sales increase.*

APPENDIX B

OTHER CONSIDERATIONS

A number of other considerations and questions frequently arise in discussions concerning the implementation of regulatory incentives. The most frequent subjects are discussed briefly below.

B.0 Effects of External Causes

One criticism of some proposals is that they fail to hold utilities harmless from factors outside the utility's control.[105] Generally, it makes little sense to have regulatory incentives in place when there is no ability on the part of the utility manager to respond to the incentive. Therefore, regulatory incentive plans should attempt to hold utilities harmless from factors truly outside their control. This policy must be considered with an appreciation of the extent to which existing regulation accomplishes this goal. For example, while weather is outside a utility's control, profits are subject to sales fluctuations caused by weather under current regulations.

Unless utility profitability is somewhat insulated from the influence of outside factors, the earning fluctuations occasioned by some factors (i.e., price of fuel) may be so large in relation to the desired regulatory incentives that the incentives become ineffective. For example, consider a plan that allows a utility's rate of return to rise or fall up to 100 basis points based on DSM program performance, but also removes all financial protection from changes in fuel prices. Once the 100 basis point cap is reached, the incentive plan is ineffective. Thus, if utility managers reasonably expect that the cap will always be hit due to changing fuel prices, the incentive plan will be much less effective than intended.[106] This is not to say that utilities should be insulated from all of the risks that bear on competitive firms.

Again, this factor should also be considered in the context of existing regulations. Under the present system, for example, utilities are not held harmless from the effects of weather and economic conditions.[107] Both these factors can have a very significant effect on utility earnings, and the fact that incentive plans also do not hold utilities harmless from changes in weather and economic conditions, therefore should not be a sufficient reason for dismissal.

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[105] *The entire notion of holding utilities harmless from factors outside their control is a subject in itself, and is unique to regulated industries. In the context of regulatory reform, critics often point out that particular proposals result in benefit or harm that flow from plant performance, fuel prices, economic conditions, etc. While regulators are generally sympathetic to some or all of these concerns, it is worth noting that competitive businesses are subject to the same considerations and are not held harmless. To be sure, these differences in the risk profiles of various industries can and should be reflected in allowed rates of return.*

[106] *For the purpose of this discussion it is assumed that fuel price changes are outside the utility's control.*

[107] *Indeed, the strong economy and hot weather of recent years has had a positive effect on utility earnings.*

B.1 Role of Unregulated DSM Subsidiaries

Some utilities already have unregulated energy service subsidiaries, and others may be in the process of seeking similar approvals. The operation of unregulated DSM subsidiaries may prove to be a useful adjunct, but the creation of such subsidiaries is no substitute for regulatory reform.

With an unregulated subsidiary, but without regulatory reform, a situation would exist where the successful operation of the unregulated subsidiary has an adverse impact on the parent utility's earnings. The question would remain whether a profit maximizing-strategy for the overall entity (the combined business of the utility and its unregulated subsidiaries) would be best served by the successful or unsuccessful operation of the unregulated subsidiary.

B.2 Distribution Utilities

Distribution companies generally purchase power from other utilities under rates or contracts approved by the Federal Energy Regulatory Commission (FERC).

In addition to factors which affect the financial incentives for other utilities (fuel clauses, rate structures, etc.) the terms of wholesale rates or contracts influence the distribution companies' incentives.

These terms are very similar to those contained in rates or contract charges between utilities and large industrial companies. In particular, the distribution company will incur a monthly demand charge and an energy charge for all power. The distribution company's costs of purchased power (capacity and energy) are ordinarily passed on to its retail customers through purchased power clauses which operate similar to a utility's fuel adjustment clause. Meanwhile, each KWH sold by the distribution company to its retail customers includes an additional component which recovers all other fixed costs. Because increased sales (to existing customers) do not increase fixed costs, each KWH has the same type of impact on revenues as it does for other utilities, albeit at a lower ~~level.~~

B.3 Multi-State Utilities

Designing incentive plans for a utility that is part of a multi-state holding company presents additional considerations.

Most importantly, correcting the incentives for the state-regulated retail utility will not affect the incentives for the parent company or for the combined company. If planning and investment decisions are controlled or substantially influenced by an entity other than a state-regulated utility, and the correct incentives do not extend beyond the state-regulated utility, any improved incentives will have little effect. To have a meaningful effect on utility behavior and investment decisions will require the Federal Energy Regulatory Commission to reform federal regulatory mechanisms. Thus far the FERC has shown no interest in LCP or any related regulatory reforms.

B.4 Combined Gas and Electric Utilities

While this entire discussion has focused on electric utilities, the incentives are essentially the same for gas utilities. Therefore, the only complication for a combined gas and electric utility relate to fuel-switching. There appears to be no general rule concerning which fuel would be more profitable to the combined entity. Thus, if this is an area of concern, a utility-specific analysis is necessary.

B.5 Unbundled Energy Services

In an ordinary shared savings approach, an energy service company[108] (ESCO) enters into a contract with a customer. The ESCO installs an energy efficiency improvement at its expense and the customer pays for it over time by paying the ESCO a share of the savings in the customer's electric bill. The customer retains the remaining savings.

Assuming a reasonably competitive market and arms-length negotiation between the ESCO and the customer, the ESCO's share of the savings compensates the ESCO for all of its costs, including a reasonable rate of return. Thus, in the context of a competitive demand-side bidding process, the ESCO's bid price to the utility will be the same as its share of the savings (adjusted for any differences in the transaction costs).

In the ordinary shared savings model, the total benefit available to be shared by the customer and the ESCO is the difference between the retail rate and the cost of conservation. The unbundled energy service proposals are structured differently.[109] The ESCO (for this first example, the ESCO is the utility) buys and installs the device and charges the customer the full retail rate for all the saved energy. Any difference between the price and the cost of the efficiency improvement is retained by the utility. Thus, in the simplest form the unbundled energy service is like a shared savings plan in which the ESCO (in this case, the utility) keeps 100% of the savings.

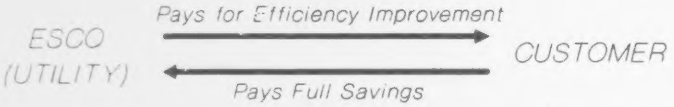

Fig. 1

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[108] *The ESCO may be a utility.*

[109] *Whittaker, "Conservation and Unregulated Utility Profits: Redefining the Conservation Market", Public Utilities Fortnightly, July 7, 1988; see also Katz, "Proper Utility Incentives: Everybody Wins", Western Conference of Public Utility Commissioners, June, 1989.*

The unbundled bidding version adds a little complexity because it can more easily occur in a three-party transaction involving utility, customer, and a separate ESCO.[110]

First, the two-party case: This case is similar to the unbundled example described above except that the utility makes a cash payment equal to the bid price instead of buying and selling the efficiency measure, and the efficiency measure is installed by the customer. Meanwhile, the customer continues to pay the full retail rate for all saved KWHs.

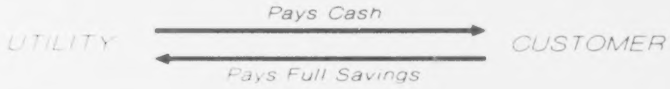

Fig. 2

Thus, if the bid price is equal to the cost of the efficiency improvement, this is also a shared savings plan where the utility retains 100% of the savings. If the bid price exceeds the cost of the efficiency improvement, the arrangement looks more like an ordinary shared savings plan.[111] From the perspective of the customer, the only situation in which this type of arrangement is superior to an ordinary shared savings plan is when the customer prefers cash to hardware. In return for this difference, the customer must participate in the bid process.

The three-party case (ESCO, utility, and customer) is more complex. These arrangements can take at least two forms. In the first, the ESCO buys and installs an energy efficiency device, the customer continues to pay the same retail bills (pays the retail price for each saved KWH), and the utility pays the ESCO the bid price.[112]

This form illustrates several important matters. First, without a payment from the ESCO to the customer, this will appear to the customer to be a shared savings plan in which 100% of the savings goes to others. Because shared savings plans have very low market penetration without a substantial payback to the customer, this approach is unlikely to produce significant results.

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[110] *Cicchetti and Hogan, "Including Unbundled Demand-Side Options in Electric Utility Bidding Programs", Public Utilities Fortnightly, June 8, 1989.*

[111] *If the purpose of bidding is to use competition to reduce the price of efficiency improvements, the bid price will equal the efficiency improvement's cost.*

[112] *A portion of the bid price may have to be returned to the customer to entice him to participate.*

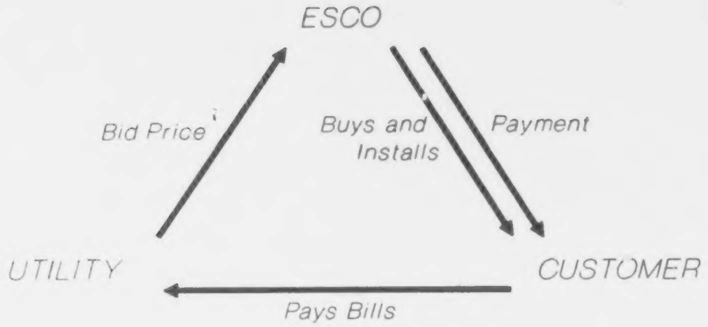
ESCO
Bid Price
Buys and Installs
Payment
UTILITY
CUSTOMER
Pays Bills

Fig. 3

Second, because the bid price cannot exceed avoided cost, any payment made by the ESCO to the customer will reduce the maximum investment the ESCO can make in efficiency equipment.

In the second form, the ESCO (the bidder) pays the utility the retail rate for bid KWHs and receives the bid price from the utility. The ESCO buys and installs an energy

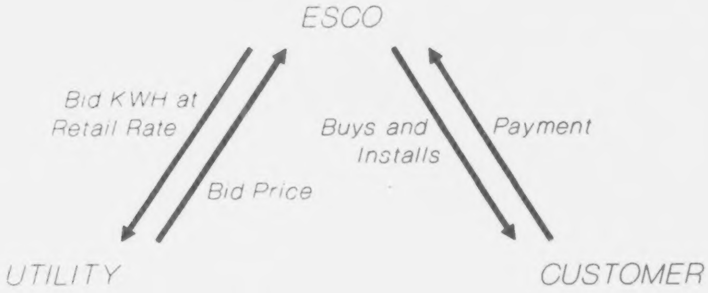
ESCO
Bid KWH at Retail Rate
Bid Price
Buys and Installs
Payment
UTILITY
CUSTOMER

Fig. 4

efficiency device and may or may not charge the customer for the service provided.

The left portion of the diagram points out that the utility payment for energy efficiency is limited to the difference between average and marginal cost. Assuming the left portion of the diagram produces no net payment, what remains is the ordinary ESCO/customer shared savings plan. If average cost exceeds marginal cost, which is the case in many parts of the country, the net utility payment is negative. To offset this impact, the ESCO would require a correspondingly higher share of the savings from the customer, reducing further the likelihood that a contract between the ESCO and the customer will be executed.

APPENDIX C

Resolution in Support of Incentives for Electric Utility Least-Cost Planning

WHEREAS, National and International economic and environmental conditions, long-term energy trends, regulatory policy, and technological innovations have intensified global interest in the environmentally benign sources and uses of energy; and

WHEREAS, The business strategy of many electric utilities has extended to advance efficiency of electricity end-use and to manage electric demand; and

WHEREAS, Long-range planning has demonstrated that utility acquisition of end-use efficiency, renewable resources, and cogeneration are often more responsible economically and environmentally than traditional generation expansion; and

WHEREAS, Improvements in end-use efficiency generally reduce incremental energy sales; and

WHEREAS, The ratemaking formulas used by most state commissions cause reductions in utility earnings and otherwise may discourage utilities from helping their customers to improve end-use efficiency; and

WHEREAS, Reduced earnings to utilities from relying more upon demand-side resources is a serious impediment to the implementation of least-cost planning and to the achievement of a more energy-efficient society; and

WHEREAS, Improvements in the energy efficiency of our society would result in lower utility bills, reduced carbon dioxide emissions, reduced acid rain, reduced oil imports leading to improved energy security and a lower trade deficit, and lower business costs leading to improved international competitiveness; and

WHEREAS, Impediments to least-cost strategies frustrate efforts to provide low-cost energy services for consumers and to protect the environment; and

WHEREAS, Ratemaking practices should align utilities pursuit of profits with least-cost planning; and

WHEREAS, Ratemaking practices exist which align utility practices with least-cost planning; now, therefore, be it

RESOLVED, That the Executive Committee of the National Association of Regulatory Utility Commissioners (NARUC) assembled in its 1989 Summer Committee Meeting in San Francisco, urges its member state commissions to:

1) consider the loss of earnings potential connected with the use of demand-side resources; and

2) adopt appropriate ratemaking mechanisms to encourage utilities to help their customers improve end-use efficiency cost-effectively; and

3) otherwise ensure that the successful implementation of a utility's least-cost plan is its most profitable course of action.

Sponsored by the Committee on Energy Conservation
Adopted July 27, 1989

Senator **Ford**. You did very well.

All four of you make statements that confuse me a little bit.

The good Doctor here compares least-cost utility planning with education and drug programs; that is a little bit hard for me to put together. And then you say the prices have to be right. Everything I do, Mrs. Ford tells me whether the price is right or not.

And we are interfering with the plumbing industry, we are interfering with washing machines, refrigerators, whatever. And it seems like we are trying to put regulations on everything.

So when we look at water conservation and we talk about conservation here, you never know whether the laundry will be clean or not when you limit it. You know, you have to have the temperature and water and so forth, and one has to depend on the other. So we get to interfering with everybody's business and we get into dotting the i's and crossing the t's, and somehow or another it bothers this one.

Then we say, no growth. And the only growth we have is foreign entities buying our country up. Toyota is sitting there with $20 billion, ready to swoop in. So all these things begin to stir in my mind, and you try to ferret them all out.

Now, let me talk a minute about what occurred here on October the 26th at our first hearing, then I want comments from all four of you. If you agree with whomever, it would be fine. But in the least-cost utility planning, DOE, in its conclusion to its statement on the 26th, made this statement, and I will read it to you:

> Conservation, fuel switching and renewable energy options should compete on equal footing with traditional resource options. The collaborative LCUP efforts that we are witnessing at the state and regional level, fostered in part by DOE's LCUP program, are moving in the direction of such competition.
>
> Meanwhile, utilities, utility regulators, and other interested groups have the freedom to experiment with alternative regulatory and incentive mechanisms that respond to national energy and environmental concerns in a manner that reflects the interest of their constituents.
>
> We support this process and think that it is working.
>
> If federally legislated adjustments to this process must be considered, it should be done with due deference to the perspectives, the concerns and needs of those currently working to enhance the role of demand-side resources and our nation's energy mix.
>
> We are not convinced that federal legislation of the type embodied in subtitle B of Title III is necessary or appropriate at this time.

Then the FERC staff makes this statement at the same hearing, and I quote:

> It is important to note that although it made a valuable contribution to this positive march of events, the PURPA model itself is not the primary vehicle being contemplated by most states and utilities for satisfying future market needs.
>
> We have learned from our experience with PURPA that its restrictions on which technologies get access to the market and its administratively determined pricing mechanism cannot produce results as effectively as a freely functioning market, which gives no technology or fuel preferential access to the market.

Does anybody want to comment on those two?

Doctor?

Dr. **Cicchetti**. Sure.

My answer to particularly the first question is that, yes, we should be putting demand-side and supply-side options on the same level playing field. But if we focus on that, we are not going to get the job done of addressing the need to bring conservation into the utility industry as a profit center and to reform regulation.

And let me tell you why the yes part works. I think that if we were looking at a lighting system in a commercial building, we should not give away the new lighting system to that commercial building and not expect them to either have to pay for the cost of the change or to continue to pay for the services of lighting that they used to pay in their electric utility bill.

And there is a very simple, straightforward way to do that, and I think it is relatively well known. If we do not do something like that, it would be as though we were paying a self-generator of electricity not to take electricity from the system, but to keep the electricity they are generating themselves.

That would be a very foolish thing to do. We only pay the self-generator when they provide electricity to the grid. Similarly, we have to have the same philosophy, I think, for commercial/industrial conservation efforts.

However, when we come to the residential level, then we have a problem. Because if we try to implement a demand-side bidding program with that same philosophy, and try to find ways to get the customer getting the benefits to pay, at least at the early stages, we are not going to get a whole lot of takers.

There is a concern that if we pay them twice, we give them an avoided cost payment, and we also let them keep the saving off their utility bill, that they might engage in too much conservation. I think that is a real concern; it is certainly a conceptual concern.

However, there is a way to avoid that and still bring residential conservation into the system. And that is to pay not the avoided cost for the residential conservation, but to pay the third party supplier whatever it takes to get them to bring the conservation into the marketplace, and then let the utility take a mark-up over that, 20 percent, 10 percent, whatever it might be, as an incentive for doing it. That is a price far less than the avoided cost payments that we are worried about—having this double payment come as a result.

So I would not apply the same kind of demand-side bidding logic to the residential sphere. I would instead look at the cost of conservation, get bids to get the cheapest price for that cost or for that conservation that is being supplied, build a mark-up over that, and not try to tie the payment to the third party vendors to an avoided cost payment, which is most likely going to be much higher.

If we follow that path, we can get on with conservation, use the information that is coming, from what works and how to quantify the results, and then put together a market where we can have more and more people pay for what they are getting—have the beneficiary pay.

But if we try to start out that way, we are simply not going to get enough residential conservation. And there are plenty of savings out there that can be purchased very inexpensively, and we need to have a system in place that will bring that about.

Senator FORD. Let us go to the utilities and see what they think.

Mr. MORRON. Well, Senator Ford, I think it is fair to say that an industry that exists with $1 billion a year and more in these kind of programs is not opposed in any way, shape or form to conservation energy management.

I think the point that I attempted to make in my testimony is very similar to the points that were made by Deputy Under Secretary Stuntz from DOE and Director Herod from FERC; that is, how you treat the conservation and load management created on your system.

The bill under consideration would ask, in fact mandate, that you treat these conservation measures as an addition to your supply side resource and to treat them as if they were bricks and mortar generators available for your customer's use.

We suggest that is an entirely inappropriate way to deal with conservation. In pages 15 through 19 of my prepared testimony I go through a fair explanation of why this comes about, but fundamentally what it really means is that there are these uncertainties and so forth, not that that should preclude you from going out and doing these things, but it ought to preclude you from putting them in your resource base.

Utilities forecast and revise their forecasts either up or down once a year based upon their best understanding and knowledge of what is going on in their service territory. If you treat conservation as a deduction from the load forecast, you are able then to make midcourse corrections, if you will, every year.

If, however, you are forced to treat conservation, a block of power conserved, as the same thing as a bricks and mortar power plant, you are unable to do that. I really would refer you to those pages in my testimony because they are at the nub of the argument here. We are not arguing against conservation or increased emphasis on conservation. We have some ideas we would suggest for what Federal fixes might be appropriate, but this just is not the vehicle to do it, Senator.

Senator FORD. Do either of the others care to comment?

Mr. Hobart?

Mr. HOBART. I might mention a slightly different point of view than that expressed by Tom. Public power systems, of course, are in the main, as I pointed out, not regulated by State commissions. They are controlled for policy, determinations by city councils and elected or appointed boards.

For that reason, there is a clear opportunity for the local community to decide what values it wants to emphasize in the provision of electricity. That actually happens in these communities.

The second point you make about purchasing conservation from third parties is that in the main, local publicly-owned utilities found it most economical to perform these energy conservation and load management functions themselves and that their costs are below those which are offered by third-party alternatives. They have proceeded in that direction.

I might offer for the committee a copy of an article which describes exactly how that was done in the small town of Osage, Iowa, a town which has received considerable acclaim because of its ability to hold its low growth static for an extended period of time and to steadily reduce its costs primarily because of its ability to use energy conservation.

Senator **Ford**. We will entertain that article as a part of the record, Mr. Hobart.

[The article follows:]

EXCELLENCE IN IOWA

Osage, Iowa, Municipal Utilities and its general manager, Wes Birdsall, are paragons for the public power industry.

Conservation programs that Birdsall has peddled one-on-one to community residents and businesses combined with an ingenious power supply strategy that allows the town to purchase 98 percent of its electricity at low interruptible rates have saved the town an estimated $1.2 million a year since 1974 while fostering economic growth in the community.

When Wes Birdsall talks about energy conservation, it's easy to see why Osage has become the state's unofficial conservation capital. He described one of the steps the utility took to encourage its customers to conserve: offering energy-saving lightbulbs to any household that had an insulated water heater. If the water heater was not insulated, the utility offered to provide a three-inch-thick jacket at no charge.

"Ninety-six percent of the people went with us," Birdsall said. He paused. "Sure makes me mad, those four percent," he added.

Birdsall's efforts have led to a 10 percent per household reduction in power consumption since 1980. Osage Municipal Utilities' last rate increase occurred in 1976 and rates have been decreased five times—by a total of 19 percent—since 1983. In February 1984, the utility cut rates 3 percent while many other utilities in the state raised rates between 10 and 30 percent. Osage's gas and electric utility is debt-free and Birdsall believes he will be able to keep rates low and possibly reduce them further.

Osage buys 98 percent of its electricity from Dairyland Power Cooperative, but also maintains five newly upgraded diesel generators for use during emergencies and shortages. The diesel generators allow Osage to buy interruptible power because the utility can carry its entire load on demand. Within 10 years, Osage will have to purchase firm power, then is likely to add a gas turbine for peaking, Birdsall said.

Osage began its conservation program when energy prices skyrocketed in the 1970s. Birdsall, who has managed the utility since 1972, decided the utility would have to halve its annual growth rate of 7.2 percent. The utility has been able to hold growth to 3 percent a year, delaying the need for construction of a new generating plant. Osage's load did not increase from 1976 to 1984, but it has grown 26 percent over the last four years, in part because of industrial expansion, Birdsall said.

Last year, Osage started a new program designed to keep industry in the town: free audits to show firms how they can save money by conserving electricity. Should the industries decide to go ahead with any of the suggested projects, the utility will pay the interest on a bank loan taken out to pay for the work.

Other conservation projects in Osage have included infrared scanning of all buildings in town to identify heat leaks, local energy efficiency standards, installation of efficient sodium streetlights, and a conservation newsletter.

All residential water heaters are now jacketed and practically every home in town is well insulated, Birdsall said. All industrial customers receive complete energy audits, 51 percent of homes and businesses have been audited, and the utility applies load management to 96 percent of Osage's central air conditioners.

Peaks at Osage are 35 percent less than those of utilities without demand-side management programs: 7 percent because of load management, the remainder thanks to other conservation measures, Birdsall said.

TREE PLANTING ENCOURAGED

The utility has a tree-planting machine and gives away trees from its own nursery to encourage residents to plant trees near their houses so they will need less air conditioning in summer. Fox River Mills Inc., a local sock manufacturer, raised output 30% in four years while spending less than 1 percent more for electricity because Birdsall and his staff helped look for ways to cut the factory's energy consumption.

Everett Steele, the owner of the local Super Valu supermarket, built a wall around some basement compressors to capture waste heat, then installed a vent and two fans to suck the hot air onto the main floor. Steele said the savings on his heating bill allow him to keep food prices about 5 percent lower, enough to keep people shopping locally instead of driving to large discount supermarkets 15 miles away in Mason City.

The utility replaced two rows of the store's fluorescent light fixtures with high-efficiency ballasts and tubes and hooked up meters to measure the difference in electricity consumption between the two types of lights. The improved fixtures used almost 24 percent less energy, Birdsall said.

The small Iowa town has attracted a good deal of media attention for its conservation program, including articles in *The Wall Street Journal* and *Time* magazine. Osage will be featured in a segment of a Public Broadcasting System television series, State of the World, to be aired next year.

The Washington-based National Energy Resources Organization presented its 1989 award for energy conservation to Birdsall last spring.

Senator FORD. Ms. Harrington?

Ms. HARRINGTON. Yes, I do have some comments. Let me put the utilities' current investment in demand side and conservation in perspective. It is a very slight investment. There are two states that have really achieved very significant conservation investment by the utilities. One is the State of Maine, and the other is the State of Wisconsin.

Those two states through very continued work by their State commissions to see that these investments are made have achieved a total in each state of about 3 percent of operating revenues invested in conservation. All of the other states average just about one-tenth of 1 percent of operating revenues for conservation. The State of California is a distant third with about one-third of its operating revenues going into conservation.

The utilities are not putting much money into energy conservation, and even the states where they have had very aggressive commissions, we have only seen this very slight improvement.

We really do need to create a conservation market. Dr. Cicchetti has told you the market is not functioning, and he is exactly correct on that point. The way to create an energy conservation market is to allow third-party vendors into it and to require utilities to purchase from them only when the qualifying vendor can sell that conservation at a lower cost than the utility can produce it themselves. No one will require a utility to purchase it at a cost higher than what the utility could do it themselves.

So we need to create the market, and it is only going to be done if in fact the obligation is placed on utilities to make these purchases.

The other point is that energy efficiency is a very enormous resource that is available for this country to tap, and we are simply not doing it. The only way we can do it is in fact to turn our major utilities around and to require them to make these energy efficiency investments either themselves or from third-party purchases. We do not know how much of this resource can be developed, but what we do know is it is much faster and much cheaper than what we are doing now for our power supply.

So in order to actually plug ourselves into this resource, we are going to have to make major reform. We are going to have to require least cost planning. Every state is going to have to do it. Every utility is going to have to do it. We really should actively develop this third-party market.

I happen to be a real proponent of bidding systems. I think that is the proper way to develop third-party market, but if you want to use the energy efficient resource—and believe me, we need to do it in this country—it is the way to produce energy resources that are environmentally benign and are at lowest cost.

We are going to have to undertake these two major steps that this legislation proposes to undertake.

Senator FORD. You talked earlier about the conservation being equal to so many megawatts?

Ms. HARRINGTON. That is right.

Senator FORD. Do you allow in Maine that to be put into the rate base?

Ms. HARRINGTON. Yes, but it does not do enough to put into rate base. Putting conservation into rate base does not make up for the lack of profit that the utility experiences through conservation investment. Putting it in the rate base is not the answer. It does not give the utility enough. It still does not provide the utility the profit that it loses by not using a supplyside resource.

Senator FORD. Are we talking about IPPs, the independent power producers, now?

Ms. HARRINGTON. We are talking about creating a body of conservation vendors called qualifying conservation.

Senator FORD. They are qualified vendors, but are they independent power producers, then?

Ms. HARRINGTON. They are independent third-party businesses which sell conservation to the utility or to a utility's customers.

I did want to mention that the NARUC has——

Senator FORD. I wish we had Jimmy Carter back. He did a pretty good job from 1976 to 1980, and then all of a sudden we let it go to hell. Today, we are spending $150 million a day for foreign energy, and it is just absolutely eating our lunch.

We have an embargo, you know, of 250,000 or 300,000 barrels per day. It scared us all to death back in 1977, I guess.

Let me ask you, Tom, should this be in the power base or the rate base?

I want to ask all of you the same question.

Mr. MORRON. Senator Ford, I think that depends upon the individual utility and its own capital structure. For example, just very recently the State of Idaho Public Utilities Commission decided to devote things. They decided to rate base the investment in conservation and load the management materials and so forth and at the same time compensate the utility via an expense mechanism of the revenue losses associated with that conservation. Other states have different mechanisms all the way through.

What we are arguing here is precisely this point. What works for Commissioner Harrington in Maine may not be appropriate for a utility in the southwest deserts of Arizona. To run a prescriptive standard across the board just is not going to work.

For example, you have Commissioner Harrington allowing some rate basing. Here in the District, you have discussion over that, and you have Idaho sitting there saying no, we are going to capitalize part of these things and we are going to expense some others. California has what they call an ERAM system, which is an advance approval of moneys to be expended and, therefore, collected through rates.

Each state does what it thinks is best for its particular set of circumstances, which is why we argue for the state flexibly as opposed to a Federal standard.

Senator FORD. Larry, do you have any comment?

Mr. HOBART. Yes, Senator. Public power systems by their nature are not involved in the same kind of rate basing questions that private power companies are. The question in the community that has a public power system is, is this a worthwhile objective which is cost effective as far as the community is concerned, and what do we have to charge in an electric bill to cover our costs to provide this service?

In a little example, the town of Trayer, Iowa decided that they wanted to be efficient in terms of lighting, so the town decided that they would replace all of the light bulbs in every home, business and industry in that community. The town paid for it and determined that it was a cost effective investment because it decreased their need to buy more electricity. That was a community decision.

Senator FORD. Is that the light bulb I buy that says 75 watts with a use of only 55?

Mr. HOBART. That kind of thing, and use of fluorescent substituting for incandescent.

Senator FORD. Doctor, do you have any comment?

Dr. CICCHETTI. Yes. This is not a yes or no question, but——

Senator FORD. Is there any area where we can get into yes and no? [Laughter.]

Dr. CICCHETTI. There is a part of it where it is yes and a part where it is no.

Senator FORD. Then the answer is no, we cannot get into a yes or no.

Dr. CICCHETTI. But on this issue, the yes and no creates, I think, the basic problem here, which is the difference between predicting energy conservation savings and observing what actually happens. When we can make the prediction and it is a reasonably good prediction—that is, where the actual more or less matches up with it—those kinds of energy conservation investments can very much go in rate base. There is not a whole lot of risk and not a whole lot of uncertainty.

So we are looking at the commercial sector and the industrial sector. The answer is rate base treatment probably makes a lot of sense.

In Wisconsin, the state in which I was the chairman of the commission, they have gone to the rate base approach, but they are emphasizing conservation in the commercial and industrial sector because it can be predicted and, therefore, lends itself to that rate base treatment and set of incentives.

When it comes to residential conservation, which I think is a place where more and more of the states are looking, maybe for good reasons based upon economics, maybe because they think that is where the greatest lack of information is and, therefore, the greatest need to make the market, we do not know what is actually going to happen.

I do not think that we should go into these things expecting that we can predict actual savings. We have to accept that going in. We do not know what is actually going to happen. We have to have a system that is flexible and one that gives the utility cost recovery based on the prediction and then gives them rewards and incentives if we over- or undersave relative to that prediction and adjusts the program over time.

That is, if we think that a water heater wrap is going to save 100 kilowatt hours per month but we learn it saves 150, then the next time around that we pay for it and build the cost flow-through mechanism in, we should use 150.

Maybe six months or a year into the program if we think that lighting loads are going to be reduced by 50 percent by certain investments and we find out that people are keeping the lights on longer because it is so cheap to keep them on, then maybe the next time around we should reduce that by whatever percentage it is that we are looking at.

Flexibility, in the program, recognizing we do not know what is actually going to happen, all these kinds of things, particularly at the household level, suggest to me that we cannot have rate base treatment. We cannot put the utility money at risk. We have to give them cost recovery for the things we are less certain about, and we have to give them some incentive to make the system work better and help educate consumers about what is trying to be accomplished by these programs.

On the other end of the scale, the commercial/industrial where we can predict, where we are reasonably certain of what the uses are of lighting in a building like this or lighting in a commercial office building, then we can in fact put the issue in or the investment in rate base and spread the money over time in terms of the benefit flow over time. I think that is a very sensible policy.

I do not think we can straightjacket the industry one way or the other and say you must do rate base regulation, because it does not even make sense to me for a particular utility to have to do everything one way. It depends which end of the spectrum we are looking at.

Senator FORD. Russell Long, a former Senator here from Louisiana, may have been right. He said the best way to conserve, instead of reducing the cost by volume, you increase the cost by volume. So as I go around and turn off all the lights in the house and as I leave a room I turn the light off, but I find that my children and grandchildren, after turning a light on, never turn it off. So you go by the house and the lights are on in every room of the house.

Now if some of them get a spanking and others do not for doing things like that, that probably is the best conservation for the kids that I know of.

My judgment is that those who say it should not be in the rate base indicate that this will not be sustained over time.

Ms. HARRINGTON. Senator, if I might, the real problem is that rate basing conservation does not go far enough. That is the problem.

When a utility invests in conservation, for each kilowatt hour conserved over and above what they forecasted they would sell in that year, once they have met their forecasted level for each kilowatt hour that they save they lose a profit on every single kilowatt hour. Rate basing the conservation that led to the savings does not make the utility whole. So rate basing is only a beginning. It does not cure the problem as to what discourages utilities from investing in conservation.

In the regulatory reform that this bill would ask states to consider, it does not say how the states must consider it or how they must implement it. It just says consider it.

But that regulatory reform and the reform that Dr. Cicchetti is speaking to this morning and the reform that is discussed in this paper published by NARUC this month dealing with this loss of profitability for utilities who invest in conservation goes much further than rate basing. What it says is that you have to make the utility whole. They have to look at least as good on their balance sheet for their conservation investments as they would for the same supplyside investment for the same amount of energy.

So rate basing is only the first step, and it does not go far enough.

Senator FORD. I think that is what I meant. Those who want it in the rate base indicate it would not sustain the utilities over time or not reimburse them for their cost. There is a thread through all of these testimonies to let them do what is best for them, rather than for us to tell them what to do.

Each of you and the doctor has been very eloquent in saying some utilities ought to be able to do it this way and some ought to be able to do it that way, and yet we are trying to mandate something, and when you try to mandate something and let them do whatever they feel like they ought to to give them some flexibility, then your mandate does not work.

So I am very concerned about mandating something, even in the form of getting them to look at it, because when you say look at it, somebody is going to grab a hold of it and push like hell, and pretty soon you will find your local commission or your state commission trying to do something that the utilities say hey, it will not work for us, and yet the doctor makes an eloquent case that you should not do it that way.

So I do not know how you make it so flexible so that you set up regulations and then you make them so flexible that everybody can do what is in their best interest.

There ought to be some carrot and stick that would make them do what we want them to do. I understood what Mr. Morron said there a moment ago, that you have either got too much generation power or not enough and you are damned both ways.

I am not sure I want to be in the utility business, unless you have one of those big smokestacks that you build out there that you do not use. You can use that as a bunker until they need it.

Mr. MORRON. My wife and I have had that same discussion.

Senator FORD. I am going to have to quit here. I am not even supposed to be here, by the way.

Dr. CICCHETTI. I would like to make two recommendations why the Committee should enact this legislation, even though we are saying keep it flexible and do not be overly onerous when you make the recommendation.

Most utilities surprise me because they are turning down the invitation by their regulators to come up with a new line of business for which they are going to have captive customers and be invited to make some additional money. And regulators like Cheryl Harrington, and she is certainly not alone, are saying we are so knowledgeable on the subject we do not just want you to make money on the sale of conservation, we are going to make up your losses when you do not sell electricity.

So you might say to yourself, why would an electric utility not want to enter that game? Why would they not want to play in that game? Well, part of it is the fear of trusting regulators, but there is another fear and this is quite real, where the other one may be real.

Senator FORD. I can understand that. I appointed some myself when I was governor. [Laughter.]

Dr. CICCHETTI. The other fear is most electric utilities today are working off of rate cases that are now a couple of years old. Sales forecasts then were much lower than they are now, and they could probably justify higher rates of return on their investment than they could today because interest rates are down.

Therefore, a state regulatory review of these issues is probably going to mean a rate case, and while a utility might be entering into a new world where it can make money, most utilities would be losing money if they had to go through a rate case process.

This Committee might be doing a lot by urging in legislation not only to have the states consider these things, that is to reform regulation, have least-cost planning, but to do it outside of a rate case process. That way, you can have the utilities seek out their self-interest, which is to go in the conservation business to make money. They can have a chance to see what the regulators really mean in terms of these changes without essentially risking what for many utilities is the first bottom line black ink that they are actually seeing in terms of cash flow in many years after the problems they have had over the last decade and a half.

So if you can find a way to change the legislation to say, let us have all this stuff that we are recommending happen, but let us have it happen outside of rate cases, then I think you are going to get a lot more benefit out of the program, because it is going to at least avoid this very real problem that most utilities have of having to go through a rate case process.

Senator FORD. Doctor—and I promised I was going to quit and I just cannot do it. There is an attitude growing that this country is not competitive any more and we need to do something about that, and then we talk about here in our legislation and it comes up, no-growth policy.

Well, that just adds more despondency to some folks out there that say not only are we not competitive, but we are putting on no-growth in our ability to generate. So 1) that says to a lot of folks that is going to be nuclear in order to keep the air, and when you have another utility that it does not increase the problem, it has to be somewhat better. Instead of being 1.2 it has to be 0.6, or something, in order to meet it, or you are trying to sell off something.

What do we say to those hard-working, so-called blue-collar people out there, who feel like we are just withdrawing and there is not going to be any competition and we are not going to be an international marketplace, when we start saying no-growth policy as it relates to generation of electricity?

Dr. CICCHETTI. I do not think we are talking about a no-growth policy.

Senator FORD. Well, there is no growth once you are in the Clean Air Act. Once you get to the point that you are down to the year 2000, you cannot go beyond that. So that means if you build it in one utility you tear down the other one, or you turn the other one off and build a new one, so that your standard will not increase.

Dr. CICCHETTI. I think when you focus on growth you talk about growth in kilowatt hours and pollutants. When I use the term, I am talking about economic productivity, and I think your question was motivated by how we do in terms of GNP relative to the other competitors we face in the world increasingly now from Europe, with 1992 looming on the horizon.

Senator FORD. Yes, they are eating our lunch—Japan and Europe both.

Dr. CICCHETTI. Conservation provides two principal reasons why we can become, as a Nation, much more competitive. The first is that, if it is cheaper, and I think in most cases it is, to conserve in the home and in the work place rather than build a new power plant, then if the only way we can have economic growth is to build power plants unless we get conservation programs, if it is cheaper—if it is half the cost or one third of the cost, it is far better to change the lighting system in office buildings instead of having to build a power plant so that the next manufacturing job can get financed through a system that is going to be using the lower-cost conservation and use the existing power plant in place to get the kilowatt hours to run that factory and that equipment.

Senator FORD. What do you tell a fellow in the western section of a time zone on daylight savings time who has to turn his lights on an hour earlier than anybody else? We waste energy that way. One little daylight saving time piece of legislation just does not increase it any more, does not make it any more money.

So in the western edge of every time zone approximately 55 minutes before, it gets as light as it does originally in the eastern part of that time zone. So for almost an hour you have lights on that would not normally come on. There is a conservation item that is automatic and we can do that here without interfering with anybody's livelihood except maybe the convenient markets and softball.

Dr. CICCHETTI. There is an important second component, and I do not want to make second sound like it is the lower number, but why if we are going to be competitive in the world we want to see conservation, this Nation's infrastructure was built on the premise that energy was very cheap, and getting cheaper.

Much of the manufacturing equipment in this country has been built on that premise and maintained on that premise. We were much more concerned when we had electric codes with safety than we were with efficiency.

We can go around and change wires in buildings and in manufacturing plants which met code, but which are very costly in terms of energy losses, and the savings that we make up from that small minor investment gives us very inexpensive energy.

So if this Nation is serious about being competitive, we would be foolhardy not to pay attention to the two principal ways in which we can get cheap electricity into our industry. One is through conservation rather than building, and the second is by having the benefit that comes from that efficiency improvement reduce the use of energy to do the same job.

Those two major benefits will put us in a much better position vis-a-vis the Japanese and the West Germans, who have always thought that energy was expensive and have an infrastructure that reflects it.

Senator FORD. I have kept this thing going, Mr. Chairman, until you got back, and I want you to know that I am delighted that you are back, so I am going to leave. But help us get away from this no-growth policy. It is a dark cloud.

It is like Joe Blpspck walking out there, you know, the dark cloud over his head. That is everywhere we go, no growth, no growth, no growth, and we have not gotten the message over that that is not what we are talking about.

So once you get to that point, then you might get some public sentiment. Right now you do not have public sentiment, except that I have been referred to as a Greenie because I voted for Senator Wirth's legislation on occasion.

Senator WIRTH. I think that was a trendy Greenie.

Senator FORD. Well, I do not know what it is, but anyhow I was concerned about the name that I was being called, but nevertheless we have got to get the attitude changed.

The moral equivalent of war was fine, but then all of a sudden for nine years we have just let it all go hang out. We just do not care, and then all of a sudden we want to put back a no growth.

We find millions of jobs going overseas, and maybe you think this is out of the purview of this hearing, but we have got to get away from this attitude of oh, we are not going to grow any more. We are going to put a cap on and we are not going to let them burn any more. We are not going to do these things. We are going back to nuclear energy.

Everybody begins to say oh, what the heck. I am not for that. I want to grow. I want to get stronger. I want to get bigger. No, we do not want you to. There is no growth.

So we have got to change the attitude of a lot of people out there in order to get back to where we are trying to get to here, in my opinion.

Senator WIRTH (presiding). Senator Ford, I do not disagree with you. I would just like to point out that there is nothing in the legislation in front of us that says no growth.

Senator FORD. But it is traveling right behind us in the Clean Air Bill, which you are very much for, and it says no growth in that bill, and that ties into what we are trying to do here. Conservation will give us what we are looking for without additional utilities. It will save generation. Is that not right? Is that not what we are trying to look at here?

Senator WIRTH. I think that is exactly right, and if we look at the United States——

Senator FORD. If you look at one piece of legislation and you do not look at the rest of them then you are in real trouble, because the puzzle has to come together at some time.

Senator WIRTH. If we look at our competitive position around the world, you know, we have two major economic competitors, the Japanese and the Germans.

The Japanese and the Germans use about half as much energy for every unit of gross national product as we do. In other words, they are producing a unit of gross national product and they have a whole lot of resources left over after they produce that unit of GNP.

The United States is wasting a great deal of energy. The argument I would make, Senator Ford, is that by pursuing an aggressive conservation program we have the ability to save significant resources, make ourselves more competitive and in fact also increase our national security.

As you know and I know, we are now more than 50 percent dependent on imported oil. That is the highest level that we have had since the early 1970s. It is unbelievable, and we sit here and fiddle while Rome burns, doing absolutely nothing about it, an Administration that refuses to recognize that we have the energy crisis on our hands that you have described so many times.

It is time for us to get serious about a balanced program that focuses on the one side on conservation and on the other starts to look at the long-term resources that we have to find.

You are absolutely right about that, but it is an overall program and until we get an administration that is serious about governing and not just presiding, we are going to have the responsibility to have to do it here all by ourselves and that is mighty tough to do.

Senator FORD. Well, you say Japan and you say Europe and so forth. Well, Japan has had to do it as far as the fuel efficient cars and lack of land area. We have been different. For 200 years we have been using whatever is necessary and you have got to change a philosophy and you are beating your head against a wall in some respects.

We have got to change attitudes, and we have been—the big car? Sure. You drive down the street today and see what the big boys from the White House drive. Hell, they do not drive some Hyundai or whatever it is. They drive the biggest Lincoln, biggest Cadillac you can get, and there is nothing conservative about that. So the attitude around here, big is better, is not necessarily true. Better is better, and we have not got that attitude yet.

Senator WIRTH. You are right, we have to change attitudes, and no one would ever accuse me of being an apologist for the White House, much less the White House's limousines. [Laughter.]

Senator FORD. I am just saying that—well, look at everybody else. You look at the limousines running around town, the big boys that come in here that are sitting at our table on occasions, and what kind of cars bring them up out front? They come up to talk about conservation. I will leave it with you, Mr. Chairman. Thank you for the opportunity. I would not have had it if you had not left. [Laughter.]

Senator WIRTH. Senator Ford, I am delighted you were here. We missed you over on the floor. We were banging the Administration.

Miss Harrington, my apologies for not being here during your testimony. We appreciate you coming down. You have been representing NARUC and I had a chance to review the NARUC testimony and we really appreciate your help.

Are there other comments for the good of the order that any of you might like to get in before we move on to our second panel, who have been waiting patiently?

I will send you all videotape of some extraordinarily good presentations on the floor this morning, talking about the delinquency of this Administration in Holland the questions raised by a number of us as to what is wrong with our leadership and why is there such enormous abdication by this White House and why are they presiding and not governing? It is really a tragic situation.

We will have questions for the record, I think particularly for you, Mr. Hobart and Mr. Morron, and you and I have had an exchange about that wording and I hope you will look at that. If we have had unintended wording there that is not what we suggested earlier, Mr. Hobart, we would hope that we could get your thoughts on correcting it because that was certainly not our intent in any way to create a kind of a two-tiered reward system. That was not our intent at all.

We thank you very much for being here.

If our second panel might join us.

Mr. Jim Wolf, Executive Director of the Alliance to Save Energy; Mr. Steve Harding, President of Puget Energy Services in Bellevue, Washington; Ms. Lydia Pastuszek, Director of Demand Planning, Northeast Power Service, New England Electric Systems in Westborough, Massachusetts; and Mr. Armond Cohen, senior attorney for the Conservation Law Foundation in Boston, Massachusetts.

To all of you, thank you very much for joining us.

And perhaps we might just go in the order in which I introduced our witnesses. You all are familiar with the rules of the committee, in which we will include your statements in full in the record. We will also leave the record open for questions afterward.

We would hope that you would be able to summarize your testimony in seven minutes or less. And in order to encourage you to do that, we will use the happy electric system up here that uses energy, but does give you a warning when it goes green, orange and red on a seven-minute cycle. And it works.

Mr. Wolf, why do we not start with you. I will say that I am very pleased to have you here. We appreciate the good work of the Alliance.

Thank you very much.

Please, proceed.

STATEMENT OF JAMES L. WOLF, EXECUTIVE DIRECTOR, THE ALLIANCE TO SAVE ENERGY

Mr. Wolf. Thank you, Mr. Chairman.

The Alliance to Save Energy is a national non-profit organization dedicated to increasing energy efficiency. We commend the provisions in S. 324, particularly those characterized by Dr. Cicchetti.

We view the primary good in the legislation as fostering the market in energy services, and we think that is a correct way to view the legislation.

It is particularly appropriate that not only will this address global warming, as you have pointed out, and the primary goal of the bill, but it will also significantly help reduce acid rain precursors, as well as having many other benefits, including some of those Senator Ford addressed on international competitiveness.

The first section in the bill, section 311, we view the primary goal as aligning regulatory, societal and shareholder interests. We believe it does leave the states the flexibility that Commissioner Harrington, Tom Morron and Larry Hobart all requested that the utilities have in their designing effective conservation programs.

We want to highlight that, in our terms, least-cost planning does not mean no new electric technologies, it does not mean conservation and sacrifice. What least-cost planning does mean is treating efficiency and conservation as a resource. We believe it will in fact promote growth and promote competitiveness.

Least-cost planning, however, most importantly, as Commissioner Harrington pointed out, does mean that a utility is going to actively embrace promotion of conservation and efficiency. As she noted, very few states are seriously, and I emphasize seriously, pursuing this goal.

In terms of the Alliance dealing with utilities, we often feel that we are trying to push the wet noodle uphill. Frankly, the attitude of many utility CEO's is "Don't try to conserve me out of business. I need to market, I need the profits, and that is how I can have a return for my shareholders."

When we have discussed this provision with them, in fact, their attitude dramatically changes. Many of them said, yes, if I can make money promoting conservation, then I will get into the business and I will do it aggressively.

What we think this provision does is it gets the market signals right, and that is to be commended. We do not want to have the utility industry conserved out of business. In fact, in the speech I gave in Michigan last week I said, I want you to make loads of money on conservation. And the utility executives said, that is the kind of environmentalist I like.

And so I think we will see more support from mid-level management in the utilities, the people trying to implement conservation programs, when they are not bucking their senior management because of the current regulatory structure.

And this bill leaves the states flexibility to do that. I think that is important. It does not mandate a single approach, as the first panel, perhaps, intimated. It mandates a standard they have to meet, but it leaves the states the flexibility to devise how they might do it.

The conservation programs utilities implement will be more effective when we align the shareholder and societal interests.

I would suggest, in the context of least-cost planning, a provision that is not in the bill, but one that we commend be inserted in the bill.

It is noticeable that the power marketing authorities, the federal marketing authorities, like TVA, WAPA, the State of Colorado, and others, are under no mandate to do least-cost planning. The only power authority that is doing least-cost planning, pursuant to congressional mandate, is Bonneville in the Pacific northwest power marketing area.

And notably, Mr. Chairman, the northwest is always pointed out as the area in the country where conservation is truly being treated as a resource. I suggest it is not accidental that, in fact, the mandate that the power marketing authorities had to do least-cost planning was a significant spurt of this activity.

So we suggest that the legislation incorporate the other power marketing authorities of the Federal Government be mandated to doing least-cost planning.

On section 312, qualifying conservation as part of PURPA. As the first panel pointed out, and Senator Ford, we believe this will significantly facilitate the market in conservation services.

PURPA was enormously successful. To be sure, there were problems of implementation, concerning costs and price to be paid. Many issues that FERC raised concerning reliability and measurement that EEI raised, a kilowatt hour saved is not equal to a kilowatt hour of supply. I think that is how I would characterize the EEI testimony.

Well, I would point out several facts. One, they are correct. A kilowatt hour saved does not emit carbon dioxide. A kilowatt hour saved does not emit acid rain precursors. And there are many other benefits to a kilowatt hour saved.

Furthermore, kilowatt hours of supply are not all fungible. A kilowatt hour from a nuclear power plant and a kilowatt hour from coal plants are quite different, in terms of their reliability. The peaking gas turbine has a different degree of reliability than does the coal plant, than does the nuclear plant, than does the efficiency plant.

The point is that conservation can and has been measured and quantified and is a resource. I think that is the goal that you have established in section 312, and we commend it.

It is not to say these are necessarily fungible. What we are saying is we demand, and it is in societal interest, that conservation be treated as a resource and to establish the market for conservation. And I think that is exactly what these provisions do.

As Commissioner Harrington pointed out, the utility industry is proud of saying they are spending $1 billion a year promoting energy conservation. But as she noted, that is less than 2 percent of the revenues of one of the largest utilities. A billion dollars a year is less than 15 percent of the cost of construction of one power plant.

From a national perspective, we are barely scratching the surface. And that is what we think has to be addressed, and this provision does.

Several concerns have been raised about whether qualifying conservation might lead to societal inefficiency. And we recognize there are legitimate questions that must be addressed. We applaud the move that many commissions have put through to accord competitive bidding as a way of getting conservation included in the marketplace.

We suggest that perhaps the qualifying conservation provision might only be made applicable to those states which do not move to competitive bidding; that includes, most importantly, demand-side bidding. We think that, perhaps, is a better approach.

In conclusion, Mr. Chairman, we think that these provisions will significantly facilitate the conservation market. It will help promote growth, it will promote competitiveness and, most importantly, it will make a significant contribution to address global warming.

Thank you.

[The prepared statement of Mr. Wolf follows:]

The
ALLIANCE
To Save Energy

1725 K Street, N.W.
Suite 914
Washington, D.C. 20006-1401
202/857-0666
Fax: 202/331-9588

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Chairman, Energy Conservation Committee
National Association of Regulatory Utility
Commissioners

James L. Wolf
Executive Director

Testimony of
James L. Wolf
Executive Director
The Alliance to Save Energy

on the provisions of S. 324
The National Energy Policy Act of 1989
relating to PURPA

before the
U.S. Senate Committee on Energy
and Natural Resources

November 7, 1989

Mr. Chairman and Members of the Committee, my name is James L. Wolf, Executive Director of the Alliance to Save Energy. I appreciate the invitation to testify before the Committee regarding the provisions in S. 324, the National Energy Policy Act of 1989, relating to the Public Utility Regulatory Act (PURPA). The Alliance to Save Energy is a national nonprofit coalition of government, business and environmental leaders dedicated to increasing energy efficiency. We conduct research, pilot projects, educational programs and policy advocacy to achieve this goal.

These provisions are a two-prong approach to foster the market in energy services. The first approach, in Section 311, is to set forth a standard for regulation concerning rates to be charged by utilities. The second approach, in Section 312, is to create a new category of technology that utilities would be required to consider for purchase. We believe these approaches are complementary.

These provisions in the bill are among the most significant to address global warming. Energy conservation and efficiency can significantly reduce the carbon dioxide emitted by utilities. They also can reduce acid rain precursors as well as have other benefits -- ensuring reliable and affordable energy for our industries and citizens, and promoting international competitiveness.

We endorse these provisions but suggest modifications to address some of the issues that have surfaced during the hearings.

I. Section 311: Aligning regulatory, societal and shareholder interests

The goal of Section 311 is to make the utilities least-cost plan its most profitable. Too often, this is simply not the case under current regulation.

Many utilities are implementing programs to promote investments in efficiency by their residential, commercial and industrial customers. This is in part due to least-cost planning requirements that are required in many states. Least-cost planning typically requires that utilities evaluate conservation and efficiency as a resource.

Least-cost planning does not, however, ensure that a utility actively embraces promotion of efficiency as a resource. Too often, the attitude of utility management is one of hostility toward conservation and efficiency -- most often because of the impact it has on shareholder interests and utility profits.

In the Alliance's report Ratebasing of Utility Conservation and Load Management Programs, we recommended that utilities be allowed to ratebase and earn a rate-of-return on expenditures in conservation just like they do on their investments in traditional supply-side technologies. Most utilities presently "expense" these expenditures on conservation -- recovering them from their customers through rates but not earning a rate of return on them. We noted, however, that even ratebasing would not compensate the utility for the revenues they lose for conscientiously seeking out and implementing conservation and efficiency improvements in their customer's facilities.

Many executives at utilities express frustration with the current regulatory approaches. They acknowledge that they are only giving demand side management (DSM) attention because of pressure from their public service commission. Often, we see commitment to DSM from mid-level management but failure of senior level management to give them the resources needed for the programs because of the concern about profits.

Section 311 changes this dynamic in a fundamental way that we applaud. It establishes a new standard for utility regulation -- permitting the utility to earn higher earning from least-cost measures -- and allows the States the flexibility to devise approaches to achieve the objective. It even gives States the ability to reject the standard so long as they consider it and publish their reasons for rejecting it.

Some States are moving on their own initiative to address this problem. New York, Massachusetts, Michigan and others are in various stages of tackling the problem. The legislation, however, will be a spur to get all 50 States rapidly moving to address a fundamental flaw with the current philosophy of regulation. It is in the national interest that we move this to top priority on the agenda of State commissions. We will see more effective conservation programs when there is a confluence of societal, regulatory and shareholder interests.

Suggested Modifications:

Applicability to unregulated utilities:
The issue of the applicability of this provision to brokers of electricity or natural gas has been raised in testimony by DOE and FERC. The legislation should be drafted so that it clearly does not apply to these types of firms. We believe, however, that its applicability to unregulated utilities functioning as distribution monopolies of either electricity or natural gas is appropriate.

Some of the largest utilities in the country are municipals or co-ops that are not subject to State regulation. Ensuring they are subject to these standards is beneficial. These electric and gas utilities should be encouraged to the extent that it is economic to promote more efficient use of electricity or gas in their customer's facilities.

Least-cost planning for federal power authorities:
A requirement that the federal power marketing authorities conduct least-cost planning should be added to the legislation. In the Northwest, the Bonneville Power Authority has been required by federal statute to periodically conduct such an analysis. As a consequence, BPA and utilities in the Northwest -- despite comparatively low energy prices -- have been leaders in evaluating and promoting conservation as a resource. No such requirement is currently imposed on the other federal marketing authorities.

We recommend that this requirement be expanded to include all the other federal marketing authorities, most particularly the Tennessee Valley Authority (TVA). TVA is especially appropriate because many of its generating facilities are among the dirtiest being evaluated as part of the current clean air debate. Promoting least-cost planning for TVA will help conservation to be treated as a resource -- benefiting both global warming as well as clean air.

Remedies:
There is no incentive or sanction in the legislation for a State that does not even consider the standard in Section 311. Perhaps a provision should be included that would make the State ineligible for federal appropriations for state and local conservation programs, if the state did not within the 2 year period consider adopting the standard.

II. Section 312 et seq.: Qualifying Conservation

Section 312 and 313 of S. 324 establishes a new category under PURPA of qualifying conservation that utilities would be required to purchase. The Federal Energy Regulatory Commission would have to establish rules for eligibility.

The section would significantly promote conservation in the marketplace. PURPA was successful in promoting the alternative power industry, although there were problems in its initial implementation. Part of the reason PURPA was necessary was because of the attitude of utility management toward alternative energy sources and independent power production. Many of these attitudes are mirrored in the attitude that is exhibited toward conservation and efficiency by current utility management.

In testimony, FERC raised several issues of implementation difficulties. However, many of these issues can readily be resolved. For instance, if there is concern that there may be too many qualified conservation entities, FERC can establish minimum size for the bid - so every person proposing to change a light bulb would not be eligible.

FERC raised other issues concerning the measurability and reliability of conservation as a resource. But, these are raised, and resolved, every time a utility in good faith formulates a least-cost plan that includes the promotion of conservation. The issues are not unique to this legislation.

Promotion of efficiency and conservation is a resource that for a variety of reasons, including some that are addressed in Section 311, of the legislation, is not receiving a fair hearing in the utility planning process. This provision will demonstrate - and encourage the tapping of - the large resource of conservation and efficiency. It will make a substantial contribution to ameliorating global warming.

Suggested modifications:

Insertion of "all resources" test:

Section 312(c)(3)(b), the so-called "no-losers test", should be deleted. It is included as an option for States to limit the amount of incentive that could be paid by a utility for a conservation investment to the difference between marginal cost and average rates. This provision is counter-productive.

The no-losers test is alleged to prevent inequity among customers and societal inefficiency. To better protect against societal inefficiency, Section 312(c)(3) can provide that States are encouraged to adopt the "all resources" test. This test considers whether the total of the resources being invested -- including the customer's investment -- is greater or less than the supply side alternative. Such a test protects against overpayments for conservation, but allows the commissions to promote conservation in instances where the rigid application of the no-losers test would prevent it. Several States now apply it as among one of many tests they consider when conservation programs are evaluated. Applying this test would also leave States free to evaluate the equity considerations as they deem appropriate.

Limiting Application of Q/C provision to States which do not have all source, including demand-side, bidding:

Some States are moving toward new procedures to satisfy requirements for capacity. These have included bidding procedures for new supply, sometimes including demand-side bidding. These procedures, it is claimed, obtain the needed capacity at a fairer price to all concerned than the traditional reliance on the PURPA model.

Competitive bidding procedures -- including demand-side resources -- are to be applauded. They are a move in the direction of market forces and away from administrative pricing that is beneficial. There are, however, important issues to be overseen in the bidding process, such as ensuring it is open and fair. Nevertheless, we believe these are manageable.

Accordingly, the qualifying conservation provision might be made applicable only in those States which have not progressed to the more market-oriented approach of bidding for both supply and demand-side resources. If a State has a bidding procedure in palace, including the demand-side, then the qualifying conservation provision would not be applicable.

It should be emphasized that even bidding procedures that include the demand-side do not, in our view, relieve the utility of its obligation to assess the market and determine whether there are opportunities for it to cost-effectively promote conservation and efficiency by its own programs.

Senator WIRTH. Thank you very much, Mr. Wolf. And I want to come back and ask you about your suggestion about WAPA and some of the marketing authorities.

Mr. Harding.

STATEMENT OF STEPHEN B. HARDING, PRESIDENT, PUGET ENERGY SERVICES, INC.

Mr. HARDING. Thank you, Senator.

It is a pleasure to be here today as a representative of a company who is one of the third parties about whom so much is being said.

I represent a company, Puget Energy Services, that is currently engaged in delivering energy efficiency resources to utilities and building owners. We are one of the companies who has contracted with Central Maine Power in their all-source solicitation, which was mentioned earlier by Commissioner Harrington.

The principal point I would like to make in my remarks today is that in over 10 years of experience both as a utility program manager and as a third party supplying efficiency to utilities, we have learned, and it can be demonstrated, that energy efficiency is a reliable resource, its deliverability to utilities in a competitive bid situation has been demonstrated in a variety of programs across the country. And the implementation risks, which were cited in earlier testimony in October, either do not arise in practice or, when they do arise, the solutions are known and have been in use for some years.

As an example of that kind of problem, the enormous number of potential respondents as qualifying conservation entities was raised as an issue that could be administratively impossible. But, in fact, in all-source bidding programs that are already in use, the number of qualifying conservation entities or the number of respondents is limited by prescribing minimum project size, by requiring bid security and other financial guarantees that only competent providers can obtain.

In fact, in the Central Maine Power solicitation, the first 100 megawatts, 13 conservation proposals were received, not an enormous number to administer. And in a more recent solicitation on the west coast for another 100 megawatts, eight conservation proposals were received, while 32 supply-side proposals were received.

We believe commission rules can easily be written to give utilities the necessary latitude to manage purchases from third parties.

We are so certain of our ability to deliver conservation resources in an effective, reliable way to utilities that we have in the past posted a $250,000 forfeiture bond as security for a promise to deliver 1.7 megawatts to the Massachusetts Electric Company in 24 months and at a fixed price.

In that contract, only effective peak demand reductions were counted according to utility-specified adjustment factors, based on the technologies we were installing and based on customer load patterns.

After 18 months under that contract, we have already met and exceeded our goal.

In this and in other programs, conservation has been demonstrated for about the last 10 years as a reliable resource, and the know-how to effectively acquire it from third parties is already available within the utility and regulatory community.

I would like to speak just briefly to a couple of specific issues in the legislation. The first one on pricing and the application of the no-losers test.

I am not qualified to speak to many of the economic arguments made about it, but I can simply tell you from my experience in the marketplace that I am not aware of any successful program anywhere in the country that is strictly applying the no-losers test. I think it often has unanticipated impacts because of the difference in rates paid by large users and small users of electricity.

Typically, small commercial and residential customers pay much higher rates than large commercial and industrial customers. So the application of the no-losers test may create and often will create a situation in which utilities can make investments for energy efficiency for their largest customers, but cannot justify it for their smaller ones.

That is a situation which is difficult to get by the headline test, and it creates a situation in which utilities look like they are providing welfare for the rich.

I would encourage the committee to consider alternate economic tests, such as the all-resources test, and I believe better information is available on those from the National Association of Regulatory Utility Commissioners.

Secondly, I have a concern that the legislation currently mirrors, for qualifying conservation entities, the language in PURPA legislation requiring that qualifying facilities have only minority ownership by utilities.

My company is a wholly owned subsidiary of a utility, as are many of the other companies engaged in this business. I am not aware of any purpose in public policy which would be served for qualifying conservation entities, other than to prevent self-dealing.

And I think a more straightforward way to prevent self-dealing is to add a rule or modify the legislation to say that for qualifying conservation entities, you simply prohibit them from selling to their affiliated utilities, but you allow them to sell to any other utility with whom self-dealing does not arise.

In closing, I would like to encourage you to keep the risks of imperfect implementation in perspective with the risks of global warming, which I think are much greater and, in fact, make the implementation risks inconsequential in comparison.

We endorse the thrust of this bill as an important step toward reducing the threat of global warming.

Thank you very much for the opportunity to make remarks.

[The prepared statement of Mr. Harding follows:]

PUGET ENERGY
SERVICES, INC.

THE NATIONAL ENERGY POLICY ACT OF 1989

TESTIMONY

OF

STEPHEN B. HARDING, P.E.

ON BEHALF OF

PUGET ENERGY SERVICES, INC.

BEFORE THE

SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

NOVEMBER 7, 1989

New England Office:
Puget Energy Services, Inc.
171 Main Street
Ashland, MA 01721

Mid-Atlantic Office:
Puget Energy Services, Inc.
525 Righter's Ferry Road
Bala Cynwyd, PA 19004

California Office:
Building Resources Mgt. Corp
1956 Webster Street
Oakland, CA 94612

Wisconsin Office:
Building Resources Mgt. Corp.
2631 University Avenue
Madison, WI 53705

1750 112th Ave. NE, Suite E-175, Bellevue, Washington 98004 USA *Tel. (206) 462-PESI*

Testimony of Stephen B. Harding, P.E.

President, Puget Energy Services, Inc.

Before the
United States Senate
Committee on Energy and Natural Resources

Washington, D.C.
November 7, 1989

Thank you, Mr. Chairman, and Members of the Committee.

It is a pleasure to be here today to talk about the experience of my company and my industry in delivering energy efficiency resources to electric and gas utilities and their customers.

I represent a private company that identifies, designs, builds, and finances energy efficiency projects in commercial, industrial, and institutional buildings. We finance energy conservation projects by making capital investments in our customers' buildings and receiving a payment for the measured savings resulting from these investments over a number of years.

The potential to reduce energy use in buildings is enormous. At present, it represents a largely untapped resource. Our business is to find these energy efficiency opportunities and invest in them, using the energy savings themselves to pay for that investment.

We do this by surveying a customer's building to identify opportunities to reduce energy use. Measures we identify typically include replacing old lighting with new, higher efficiency light sources, installing and programming computer-based temperature controls, and modifying or replacing heating and cooling systems to improve their efficiency.

We then propose to install the measures we have identified with no out-of-pocket investment by the customer. We finance all of the design and construction costs. Once the measures are installed and functioning, the customer pays us a percentage of the measured savings resulting from our work. Typically, these payments would be made over a five to ten year term.

Because the payments to us are determined by the measured performance of the efficiency improvements, we bear the financial risk of loss if the measures do not perform as expected. The customer pays only for what he gets, after he gets it. For this reason, companies like ours are often called performance contractors.

Many of our projects include purchases of conserved energy by utilities. We are a wholly-owned subsidiary of an electric utility and operate nationally, with our business concentrated in the Northeast, Northern Midwest, and West Coast. We are presently providing capacity through energy efficiency to utilities including Central Maine Power, Massachusetts Electric Company, Boston Edison, Madison Gas & Electric Company, Seattle City Light, and the Bonneville Power Administration. We have hands-on experience with a great variety of approaches to utility purchases of conservation and insight into building owner attitudes toward energy conservation.

A number of witnesses and senators have testified in previous hearings to their perception of likely difficulties in implementing purchases of conservation by utilities; the background memorandum circulated prior to these hearings mentions three specific areas of concern: measurement of electricity savings, attribution of savings to utility investments, and pricing.

The obstacles raised by previous witnesses may seem profound to anyone who is not familiar with implementing conservation as a utility resource, but they are not large obstacles to those of us who have been engaged in this business for the last decade or so. All of the difficulties described have been considered, addressed, and solved in a number of utility programs nationwide. These solutions have been acceptable to the utilities purchasing conservation, as well as to the regulators, ratepayers, vendors, contractors, and the property owners and occupants whose buildings are ultimately affected.

I will describe just two of the different approaches we have used to provide accurate measurement and delivery of electricity savings. These examples are from different geographic regions with vastly different retail energy rates and involve building owners from different sectors and with completely different investment criteria and decision processes. They also resulted from completely different utility procurement designs.

The first program I will describe is the Purchase of Energy Savings Program, which was a program developed by the Bonneville Power Administration to demonstrate acquisition of energy conservation in existing commercial buildings.

Under this program, Bonneville retained us to market and implement energy conservation in any commercial buildings we selected anywhere in Bonneville's service territory. Savings measurement and pricing methodologies were agreed to in advance, but specific buildings and measures were not identified.

We installed efficiency measures in several commercial and public buildings including office buildings, a community college, and state social service buildings. Puget Energy Services secured agreements from the building owners to participate, identified efficiency measures, installed them, and financed all project costs.

The program incorporated a number of features to ensure that Bonneville received what they paid for. First, Puget Energy Services receives payments only for electricity savings measured against a baseline of energy use, using building utility meter data for a calendar year. The occupancy and operation of participating buildings was documented by Puget Energy Services and verified by Bonneville staff. A computer model of the buildings' thermal performance was used to determine what portion of the variation in energy use was weather-related, and measured savings were adjusted for weather variations.

In addition, we were required to estimate the savings we expected in the buildings and document these estimates and the engineering methods used to make them. Bonneville reviewed and approved our calculations. Payments for measured savings are capped at the level of estimated savings. Even if actual savings exceed the estimates, we are paid only for the estimated savings level. In other words, we are paid for actual savings or estimated savings (estimates are based on generally accepted engineering practices), whichever is less.

This cap on payments was designed to prevent overly conservative analysis methods from inflating the price Bonneville paid.

We are required to ensure that the measures we installed are operated and maintained properly over a seven year period, which is also the term of Bonneville's payments to us. This provision was included to ensure that

Bonneville would receive the estimated energy savings over the entire period for which it was relying on them.

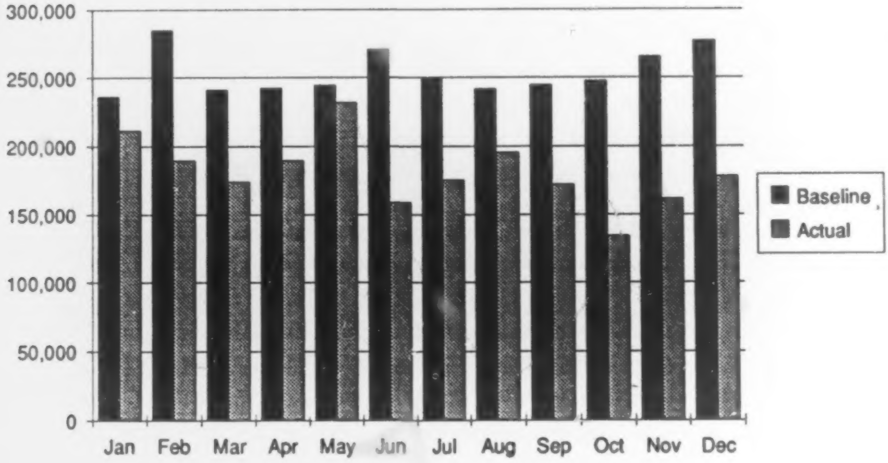
In the figures on the following page, I have illustrated the results from just one of the buildings in which we installed measures. In each year since the measures were installed, actual savings have exceeded our estimate. Ownership of one of the buildings we modified has changed without affecting the savings performance of the measures or our relationship with Bonneville. The savings will be delivered for seven years at a price lower than Bonneville anticipated, since the performance of the measures is above estimates.

In another program with Central Maine Power, we identified over one megawatt of capacity reductions through lighting efficiency in two industrial facilities. We identified the electrical circuits within the facility that would be affected and developed a measurement plan to separate the impact of our measures from all other energy use variations in the plants. Every detail of the project was developed in advance and submitted to the utility so that they could evaluate the reliablility of our project in competition with other demand-side and generation proposals received as part of an "all-source" auction.

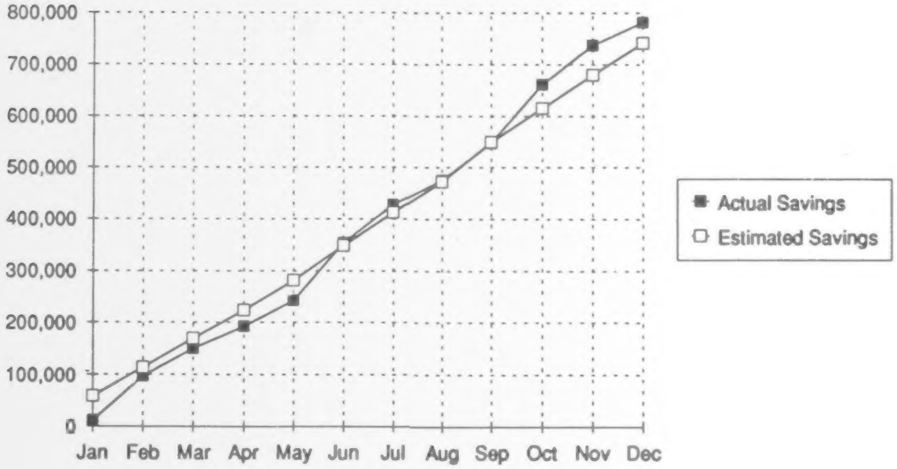
The two projects identified by us were selected by Central Maine Power and are largely completed. A copy of a press release by the utility describing the projects is attached.

As in the Bonneville program, Central Maine Power verified the technical basis for our savings estimates but pays on the basis of measured reductions in load and energy use.

As an implementer of energy conservation resources for utilities, we are so confident of our ability to identify, deliver, and measure energy conservation that we have provided surety bonds to guarantee delivery at a fixed price and on a fixed schedule. In 1988, my company provided a guarantee that we would deliver 1.7 megawatts of capacity reductions within two years in 100 commercial and industrial facilities in Massachusetts. We provided a forfeiture bond for a quarter million dollars to New England Power Company to back up this guarantee. After only eighteen months we have already provided over 2.5 megawatts of capacity



Baseline vs. Actual Use - Office Building
Purchase of Energy Savings Program



Savings Performance - Office Building
Purchase of Energy Savings Program

reductions and we anticipate that within the two-year schedule we will deliver a total of nearly 3 megawatts, almost twice the amount we guaranteed.

A few innovative and energetic utilities are already purchasing conservation and one entire region of the country, the Pacific Northwest, has been acquiring conservation as its resource of first choice for nearly ten years. The experience and know-how to acquire conservation as an economical, reliable resource already exists within the utility, engineering, and construction industries.

Utilities such as New England Power Company, Central Maine Power, Northeast Utilities, and Boston Edison Company deserve praise and recognition for their leadership in implementing conservation and demand reductions as a resource. But these utilities are by no means representative of utilities across the country. Only in New England, the Pacific Northwest, and Wisconsin is there really aggressive utility investment in energy efficiency. In other parts of the country there is often ambivalence or even outright hostility on the part of utilities toward consumer efforts to reduce energy use. One reason for these utility attitudes is that current regulatory practices generally penalize utilities for effectively promoting efficient use of energy.

Utility investment in energy conservation as a resource is the exception, not the rule. It is contrary to decades of utility management practice and habit. Without a Federal mandate, utility investment in low-cost energy efficiency will proceed more slowly and cost-effective opportunities to reduce global warming through efficiency improvements will be lost.

To summarize, conservation is a reliable, economical energy resource that can be purchased by utilities from third-party sources. This is already being done by utilities in New England and the Pacific Northwest. The know-how to address implementation obstacles is already widely available.

Without Federal encouragement, many states and utilities will move more slowly to develop this non-traditional resource, not because it is not proven or cost-effective, but simply because it is non-traditional. This delay will affect consumers through higher bills in existing buildings and lost opportunities in new construction, where energy efficiency can be built in from the start much more cheaply than it can be added later.

I'd like to close by stepping back from the implementation details I have been discussing to the larger picture and the purpose of the legislation under consideration. Most of the objections in the testimony to this bill amount to objections that its implementation will be imperfect. It is important to keep the risks inherent in the implementation of any new policy in perspective with the risks of global warming.

This situation is like driving on a foggy night down a mountain road with a five foot ditch on one side and a five hundred foot cliff on the other. While we want to avoid the "ditch" of imperfect implementation, we certainly should be willing to steer closer to *that* side of the road to avoid the "cliff" of global warming.

We endorse the intent of S. 324 as one step toward mitigating the risks of global warming. Thank you, Mr. Chairman and Members of the Committee, for this opportunity to present our views on this vital issue.

For Release: Immediate

Contact: Clark Irwin

AUGUSTA, Maine, Oct 7, 1988 -- Central Maine Power Co. has signed two contracts with an energy-management firm that will save electricity for other customers' use through efficiency improvements at Maine industrial plants.

The contracts in CMP's "Power Partners" program are with Puget Energy Services, Inc., a Washington state-based firm that finances, designs and manages energy-efficiency projects throughout the commercial, industrial, and institutional sectors.

Puget has based its contract commitments with CMP on studies and discussions with two large industrial customers of CMP.

The ultimate locations of the energy-saving work remain subject to mutual agreement between Puget and its business partners.

Puget proposes to replace existing lighting systems in the business with more efficient ones. Older mercury, metal halide, incandescent and fluorescent systems will be replaced by high-pressure sodium and new metal halide systems.

At one location, the proposed work would save 7.7 million kilowatt-hours a year and would reduce the customer's peak demand by 948 kilowatts.

At another, 2.8 million kilowatt-hours would be saved a year and demand would be reduced by 329 kilowatts.

CMP's contract calls for payments over eight years to Puget in the amount of about $1.3 million for one project and around $500,000 for the other proposal (in present-value dollars).

The estimated retail savings in the first year for one industrial customer is $332,864, and for the other, $124,369.

For other CMP customers, the KWH savings guaranteed by the contracts each year -- enough to supply about 1,400 typical residential customers -- is the equivalent of having a new generating plant come on-line. But the cost is 5 percent lower and the environment benefits from the more efficient use of resources.

The Power Partners contract provides energy savings for the host site, energy planning assurances for CMP and discount-price supplies of freed-up energy for other CMP customers.

CMP operates an array of energy management programs that have already released more than 100 million KWH for customers' use and trimmed last winter's peak demand by more than 100 megawatts of power. The utility recently announced a five-year program of more than $100 million to maintain and expand energy-management programs for its customers.

SAFECO

CONTINUATION CERTIFICATE

SAFECO INSURANCE COMPANY OF AMERIC
GENERAL INSURANCE COMPANY OF AMERI
FIRST NATIONAL INSURANCE COMPANY
OF AMERICA
HOME OFFICE: SAFECO PLAZA
SEATTLE, WASHINGTON 98185

SAFECO INSURANCE COMPANY OF AMERICA, Seattle, Washington, Surety upon

a certain Bond No. 5518495

dated effective April 13,1988
(MONTH, DAY, YEAR)

on behalf of PUGET ENERGY SERVICES CO., INC.
(PRINCIPAL)

and in favor of NEW ENGLAND POWER COMPANY
(OBLIGEE)

does hereby continue said bond in force for the further period

beginning on April 13, 1989
(MONTH, DAY, YEAR)

and ending on April 13, 1990
(MONTH, DAY, YEAR)

Amount of bond ONE HUNDRED SEVENTY TWO THOUSAND,EIGHT HUNDRED TWENTY FOUR AND NO/100----------------------- Dollars. ($ 172,824.00)

Description of Bond ENERGY REDUCTION BOND

Premium: $ 2,622.00

PROVIDED: That this continuation certificate does not create a new obligation and is executed upon the express condition and provision that the Surety's liability under said bond and this and all Continuation Certificates issued in connection therewith shall not be cumulative and that said Surety's aggregate liability under said bond and this and all such Continuation Certificates on account of all defaults committed during the period (regardless of the number of years) said bond has been and shall be in force, shall not in any event exceed the amount of said bond as hereinbefore set forth.

Signed and dated on April 13, 1989
(MONTH, DAY, YEAR)

SAFECO INSURANCE COMPANY OF AMERICA

By Lori Whitted
Lori Whitted Attorney-in-Fact

1953

SAFECO

SURETY RIDER

SAFECO INSURANCE COMPANY OF AMERICA
GENERAL INSURANCE COMPANY OF AMERICA
FIRST NATIONAL INSURANCE COMPANY
OF AMERICA
HOME OFFICE: SAFECO PLAZA
SEATTLE, WASHINGTON 98185

To be attached to and form a part of

Type of Bond: Energy Reduction Bond

Bond No. 5518495

dated effective April 13, 1988
(MONTH, DAY, YEAR)

executed by PUGET ENERGY SERVICES CO., INC., as Principal,
(PRINCIPAL)

and by Safeco Insurance Company of America, as Surety,
(SURETY)

in favor of New England Power Company
(OBLIGEE)

In consideration of the mutual agreements herein contained the Principal and the Surety hereby consent to changing

the limits of liability

From: TWO HUNDRED FIFTY FOUR THOUSAND, FOUR HUNDRED FOURTEEN AND NO/100---
($254,414.00) DOLLARS

To: ONE HUNDRED SEVENTY TWO THOUSAND, EIGHT HUNDRED TWENTY FOUR AND NO/100--
($172,824.00) DOLLARS

Nothing herein contained shall vary, alter or extend any provision or condition of this bond except as herein expressly stated.

This rider is effective April 13, 1989
(MONTH, DAY, YEAR)

Signed and Sealed April 12, 1989
(MONTH, DAY, YEAR)

PUGET ENERGY SERVICES CO.,INC.
PRINCIPAL

By: ____________________
TITLE

SAFECO INSURANCE COMPANY OF AMERICA
SURETY

By: ____________________
ATTORNEY-IN-FACT
Lori Whitted

SAFECO

SAFECO INSURANCE COMPANY OF AMERICA
GENERAL INSURANCE COMPANY OF AMERICA
FIRST NATIONAL INSURANCE COMPANY
OF AMERICA
HOME OFFICE: SAFECO PLAZA
SEATTLE, WASHINGTON 98185

Bond No. 5518495

KNOW ALL BY THESE PRESENTS, That we, PUGET ENERGY SERVICES, INC., as Principal and THE GENERAL INSURANCE COMPANY OF AMERICA, a corporation organized under the laws of the State of Washington, and authorized to transact the business of surety in the State of Massachusetts as Surety, are held and firmly bound unto NEW ENGLAND POWER COMPANY, 25 Research Drive, Westborough, Massachusetts as Obligee in the just and full sum of TWO HUNDRED FIFTY FOURTHOUSAND, FOUR HUNDRED FOURTEEN AND NO/100----------- ($ 254,414.00 * *) DOLLARS, for which sum, well and truly to be paid, we bind ourselves, our heirs, executors, administrators, successors and assigns, jointly and severally, firmly by these presents.

Sealed with our seals, and dated this 20th day of April, 19 88.

THE CONDITION OF THIS OBLIGATION IS SUCH, That, WHEREAS, PUGET ENERGY SERVICES, INC. is entering into a Subsidy Agreement with the Olbigee as of April 13, 19 88, which by reference is made a part hereof, for installing certain electric energy conservation measures (Demand Reduction Goal) in customer's facilities designated in Attachment A of said Agreement, and,

WHEREAS, the Obligee has requested security from the Principal to cover damages which may be suffered by the NEW ENGLAND POWER COMPANY should Principal fail to achieve the "Demand Reduction Goal" and,

WHEREAS, this bond is furnished as Security pursuant to Attachment D of said Agreement.

NOW, THEREFORE, If the said PUGET ENERGY SERVICES, INC. shall promptly and faithfully pursue the Electric Conservation Measures in compliance with the terms and conditions of the Subsidy Agreement then this obligation to be void; otherwise, to remain in full force and effect.

PUGET ENERGY SERVICES, INC.

By:________________________

GENERAL INSURANCE COMPANY OF AMERICA

By: Lori Whitted
Lori Whitted, Attorney in Fact

Countersigned:
Marsh & McLennan, Inc. by
Gregory M. Neal, Vice President
Gregory M. Neal

Senator WIRTH. Mr. Harding, thank you very much.

I meant earlier to ask Mr. Bar-Lev to come up and join us on this panel.

Ms. Pastuszek, would you proceed?

STATEMENT OF LYDIA M. PASTUSZEK, NEW ENGLAND ELECTRIC SYSTEM COMPANIES

Ms. PASTUSZEK. Thank you, Senator. It is a pleasure to be here today. I am here representing the New England Electric System Companies. We serve about 1.2 million customers in Massachusetts, Rhode Island and New Hampshire.

We have been practicing least cost planning and are counting on demandside resources to supply about one-third of our required new resources over the next 15 years or about 1,000 megawatts.

We have had an active full-fledged conservation and load management program under way since mid 1987. We have been conducting demandside research and development for over ten years. To date, we have over 200 megawatts of reductions in place or under contract. Over 100,000 customers have participated in our programs.

In 1989, we are spending about $40 million on these programs. In 1990 we plan to spend $65 million. In short, we have spent ten years planning and two and a half years implementing a conservation program that works.

In addition, we substantially contributed to the development of the conservation marketplace because the bulk of the dollars we spend flow to outside vendors, businesses and suppliers. In fact, one of our subsidiaries, Massachusetts Electric Company, has the very contract that was referred to by my colleague from Puget.

My written testimony and comments today discuss some of the practical aspects of achieving the efficiency goals of S. 324. My focus will be on the posted conservation price approach contemplated by the bill.

Our experiences with demandside bidding which would result from a posted conservation price are discussed fully in a paper attached to my written testimony. The major lesson learned from our experience is that third-party conservation suppliers are an important player in the delivery of successful conservation programs. However, they cannot deliver demandside reductions at the level of activity that is required to meet short-term capacity needs.

Instead, well-designed utility sponsored programs can and should be mobilized to penetrate the market. We have combined the expertise of our staff with that of interested outside parties and national experts in demandside programs brought in by the Conservation Law Foundation. This unique collaborative effort has resulted in programs which are carefully marketed, monitored and evaluated to assure high penetration rates and high quality results.

Introducing the posted conservation price scheme at this point in time will complicate our progress. It will also detract from the efforts of flexibility that State regulators need to encourage demandside activities given the particular circumstances of the state and the service territory.

For example, conservation bidding is likely to be more active to the large commercial and industrial sector than it will be for the residential sector, and programs must be developed to reflect these differences. New England Electric has demonstrated that utility-sponsored programs can effectively penetrate the market and result in meaningful efficiency improvements.

Regulatory treatment of utility conservation and load management investments which encourage such activities will be a critical motivating factor in accelerating such investments throughout the utility industry.

One of the practical consequences of posting conservation price is that conservation could be more expensive than through a utility-sponsored program. The utility-sponsored program is based upon costs, costs which are well below those of even the most attractive supplyside options.

The posted price sets a maximum price level against which bidders will compete. The selected bids may then be the least costly of the bids received, but they may not be the least costly way in which to implement the selected conservation program.

Further, the quickest way to achieve the efficiency goals of S. 324 is to take full advantage of the unique relationship utilities have with their customers. Utility-sponsored programs do this by combining the utility's knowledge of the customers, businesses and electricity use with their credibility with the customer.

The utility also has a long-term relationship with the customer to consider, which means they have an interest in making sure the conservation measures work in the long run.

I feel that New England Electric System Company's demandside programs have been successful in delivering real cost effective demandside resources. We want to continue these programs because they are least cost and an environmentally sound alternative. We would like to see a regulatory structure that promotes and rewards such investments and would like to continue our role in the conservation marketplace.

Thank you for the opportunity to speak today.

[The prepared statement of Ms. Pastuszek follows:]

THE NATIONAL ENERGY POLICY ACT OF 1989

TESTIMONY OF

LYDIA M. PASTUSZEK

ON BEHALF OF THE

NEW ENGLAND ELECTRIC SYSTEM COMPANIES

BEFORE THE

SENATE COMMITTEE ON ENERGY

AND NATURAL RESOURCES

HEARING ON S. 324

NOVEMBER 7, 1989

The New England Electric System has three wholly-owned retail electric subsidiaries serving about 1.2 million customers in Massachusetts, Rhode Island and New Hampshire (see Figure 1). System peak demand is about 4200 MW, generally occurring in the summer. Since 1979, when the System published its 15-year long range plan, NEESPLAN, the System companies have been active in developing conservation and load management programs that can defer the need for traditional generating capacity.

In 1985 the System incorporated least cost planning into its second long range plan, NEESPLAN II. This made us one of the first utilities to implement a balanced planning process which considered generation and conservation options within the same modelling framework using consistent economic criteria. The methods and models utilized to conduct this analysis were developed by company staff because adequate tools to carry out the analysis were not commercially available. A schematic description of the companies' planning process is attached as Figure 2.

In 1987, the System began implementing an ambitious conservation and load management program--Partners in Energy Planning--which has a current goal of reducing the peak demand for electricity by 300 MW by 1991. To date, the System companies have achieved about 115 MW of that goal in demonstrated demand-side reductions, with an additional 70 MW under contract. The System's long range plans indicate that about one-third of new resources implemented over the next 15 years will be demand-side resources (see Figure 3). To achieve these reductions the System companies will spend about $40 million on conservation and load management programs in 1989. Projected 1990 spending will be about $65 million or approximately 3-3.5% of total revenue. This percentage places us in the forefront of utility conservation and load management spending.

During the 5 year period from 1984 through 1988, demand for electricity in the New England Electric service area has grown at an average annual compound rate of 5.0%. Strong growth in the demand for electricity also prevailed in the New England region as a whole throughout this period. Since the New England Electric companies are members of the New England Power Pool, regional demand growth coupled with strong service area growth, led to a tight capacity situation over the past few years. The System implemented its conservation and load management programs to help address its very current and urgent need for additional electric capacity. In short, the New England Electric System companies have undertaken conservation and load management programs because they offer a viable alternative resource for meeting our customers' need for electricity.

CURRENT REGULATORY PRACTICES

Current regulatory practice in most states does not directly reward utilities for engaging in conservation and load management programs. We are working on creative ways of financing our expenditures on conservation and load management although initially, the System companies implemented these programs without a means for recovering their costs nor a means for earning a return for shareholders. Since most utilities are profit making entities even those pursuing some sort of least cost planning often have little incentive to undertake conservation and load management programs.

NEES' companies have made proposals to their three state regulatory commissions to recover the costs of the 1990 conservation and load management programs and to create an incentive for such programs. (Docket No. 89-195 before the Massachusetts Department of Public Utilities, Docket No. 1939 before the Rhode Island Public Utilities Commission, and Docket No. 89-154 before the New Hampshire Public Utilities Commission). The companies' proposals are supported by the Conservation Law Foundation of New England, a leading environmental organization. In a unique cooperative and voluntary association, the CLF brought in a team of experts who reviewed and helped design the System's conservation programs. The programs which are now being implemented are on the cutting edge of conservation programs in the country.

The System and CLF also worked jointly on developing the cost recovery proposal which is before our three state regulatory commissions. The cost recovery proposal would enable the companies to retain a share of the value that the conservation and load management programs create through avoiding the need for additional generating capacity. This approach to rewarding utilities for aggressively pursuing demand-side management through least cost planning is consistent with the Energy Conservation Committee of the National Association of Regulatory Utility Commissioners who unanimously adopted the position that "A utility's least cost plan for its customers should be its most profitable plan." It is our hope that the three regulatory commissions before whom we have brought our proposals will act to create the appropriate incentives for utility companies to embrace conservation and load management investments.

ENERGY EFFICIENCY

There is significant potential for conservation in the current marketplace. Currently real energy prices are at an all time low. This contributes to a general complacency in the country about the adequacy of future energy supply and the need for conservation.

Through increased efficiency conservation programs can avoid increases in emissions such as sulphur dioxide (SO_2) and nitrogen oxides (NO_x). While the long term impacts of CO_2 emissions, global warming and greenhouse effects are not yet well understood, energy efficiency will also reduce CO_2 emissions. Unfortunately there are numerous market barriers to increasing energy efficiency. For example, an average office building's energy consumption is 1-3% of its total operating cost and managers often want to see savings in 1 or 2 years equal to the cost of the conservation measure. This is a short term approach which is in direct contract to the long-term utility investment horizon. Therefore, government and utilities have to take an active approach to help diminish the impacts the increased energy consumption from inefficient building practices will have on our environment. New England Electric has supported higher efficiency standards for appliances, HVAC systems, building shells and lighting.

SPECIFIC COMMENTS ON S. 324

Conservation and load management programs can cost-effectively and substantially increase the efficiency with which we use energy. In the New England Electric service area, the driving forces behind the implementation of conservation and load management has been its cost-effectiveness combined with tight capacity supply, growing demand and opposition to new power plants. The resulting impact on emissions is an additional benefit, and one which our regulators are beginning to address by requiring that externalities and a societal perspective be taken when developing long term resource plans. Further, the Massachusetts Acid Rain Reduction plan specifically allows utilities to take credit for conservation reductions in meeting emissions targets.

S. 324 proposes a scheme whereby utilities would be required to post a price for conservation, much like the current system for encouraging qualifying facilities under P.U.R.P.A. While the New England Electric System companies agree with the underlying principle that utilities should be willing to buy conservation just as they buy traditional supply, we do not agree that the method laid out in S. 324 will be the most effective method for stimulating conservation at the current time.

Posting a price for conservation in today's conservation market can lead to the company and its customers having to buy conservation measures at a much higher cost, which is in direct contradiction to the stated goals of S. 324. For example, many of the programs we sponsor involve the direct installation of conservation measures which in most cases is significantly cheaper than generation capacity. If the conservation supplier market was truly competitive then the bids we receive would be only slightly higher than what it costs us to install the same conservation measures. If bidders know that we can pay up to the avoided cost of generation capacity they will bid only slightly below that level regardless of the cost of the conservation measure.

As further evidence of this point, consider the following experiences. Almost all of NEES' 115 MW of conservation and load management in 1989 is due to utility sponsored programs, with only 5 MW (with an additional 5 MW under contract) due to conservation bidding. This 5 MW reduction is the result of a bid that produced only three qualified bidders. NEES signed contracts with all three bidders, a less than perfect situation that indicates the lack of an advanced conservation supplier market. In other words, conservation suppliers alone cannot meet the demand for least cost conservation programs.

While it can be argued that the effect of posting a price for conservation will in fact contribute to the development of such a market, I feel that in the short term this will occur at the expense of customers, who will pay higher costs to help foster this market and may not receive the same quality of conservation services as they could from a utility-sponsored programs. This is especially problematic when a utility has a present need for capacity, since the avoided cost ceiling will be relatively high. This is the case in the New England Electric service area. Rather than requiring regulatory commissions to require companies to post such a price, the commissions should be permitted to structure regulations and incentives which best suit the needs and circumstances of the companies they regulate.

Once the utility is obligated to post a price for conservation, the incentive for the utility to be interested in stimulating the development of a conservation market and infrastructure is removed. The utility becomes indifferent to the improvement of that market because its customers no longer benefit from the development. In the long run, this will slow the delivery of quality conservation services.

The utility has an existing unique and long term relationship with its customers that enables it to successfully offer effective conservation services. The quickest way to achieve the efficiency goals stated in S. 324 is to take advantage of this unique relationship. Utilities should be the primary provider of conservation services as well as of electricity services because it is in their interest to do so. To the extent that the proper regulatory incentive can encourage and enhance utility interest in conservation, the conservation will occur even more quickly and deeply. And, as a consequence of the utility-sponsored programs, the conservation marketplace will also develop because the utility will retain the services of contractors and suppliers many of whom may be the very same people and businesses who would be interested in submitting conservation bids. At NEES approximately 90% of our conservation and load management direct installation dollars go to these businesses.

Coordinating a utility-sponsored program along side a conservation bidding program does pose practical problems. Among these problems are ensuring that the two approaches do not duplicate one other, the need to coordinate customer contacts, and the requirements of measuring performance. At NEES, we have addressed this added complexity by setting aside a specific group of customers as the exclusive market for the conservation suppliers' bids; in other words, our standard utility-sponsored program package is not available to these customers. This avoids having the utility and conservation supplier "wooing" the same customer, which ultimately results in confused customers.

Finally, should utilities be required to post a price for conservation, bidders should be required to specify the details of the conservation resource to be supplied, including the seasonal and daily load shape impacts, the target customer segment, the measures and products to be installed, the measurement method, the marketing plan, and the schedule. The utility could then evaluate the project benefits on a comparable basis to the other resources available to it to assure that the project was consistent with the assumptions underlying the posted price. Problems similar to those encountered with early PURPA supply regulations may be encountered with conservation unless flexibility in pricing is worked into the process. Posting a price is a small piece of the effort required; section 313 (c) (3) recognizes the controversy over the issue of conservation pricing, yet does not pose a solution to the controversy.

In summary, the stated intent of S. 324 to encourage the development of cost effective efficiency programs is hindered by the approach it proposes to develop a conservation marketplace. The approach does not recognize the critical role that successful utility-sponsored programs should play in achieving this goal. New England Electric, along with several other utilities in the country, has shown that utility-sponsored programs can effectively penetrate the market and result in meaningful efficiency improvements. Encouraging utility commissions to provide appropriate incentives to encourage utility investment in conservation will be much more effective than the prescriptive approach currently contemplated in S. 324.

FIGURE 1

NEW ENGLAND ELECTRIC
SERVICE AREA

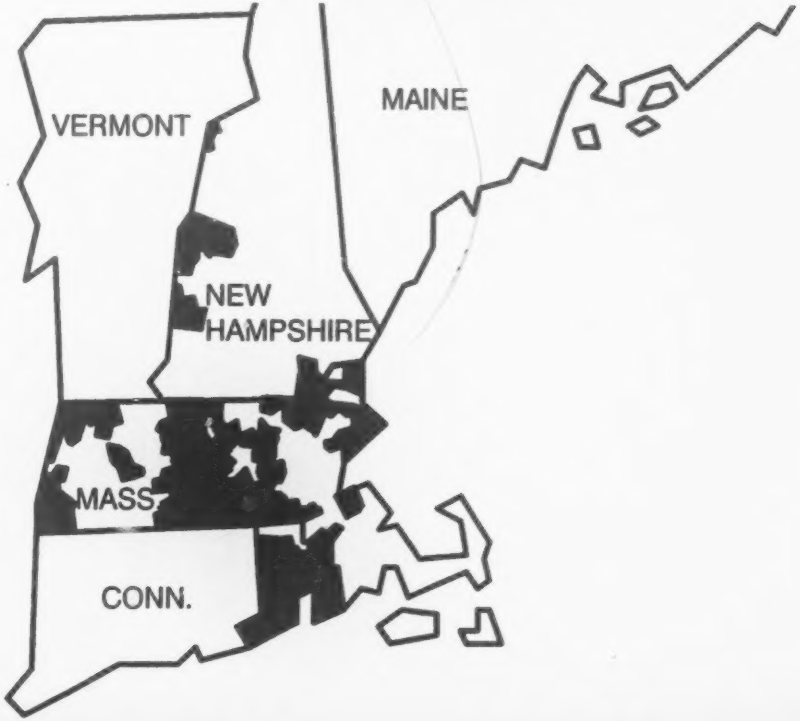

MAINE
VERMONT
NEW
HAMPSHIRE
MASS.
CONN.

FIGURE 2

Planning Process

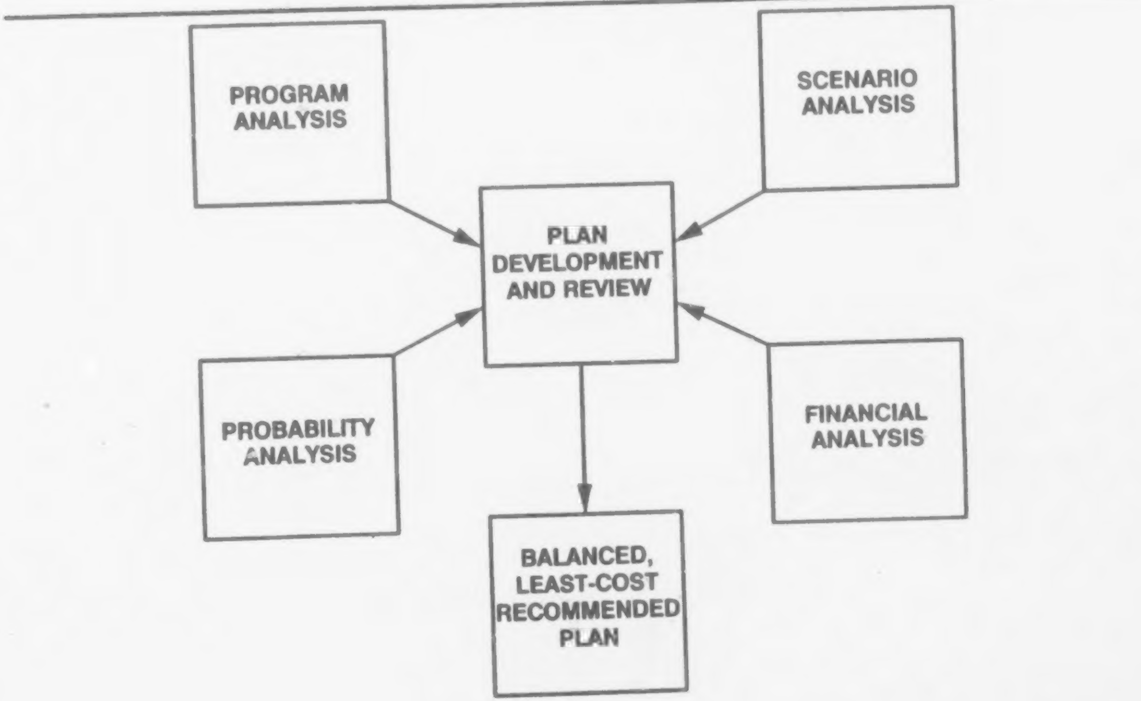

PROGRAM ANALYSIS
SCENARIO ANALYSIS
PLAN DEVELOPMENT AND REVIEW
PROBABILITY ANALYSIS
FINANCIAL ANALYSIS
BALANCED, LEAST-COST RECOMMENDED PLAN

FIGURE 3

Projected Resource Mix

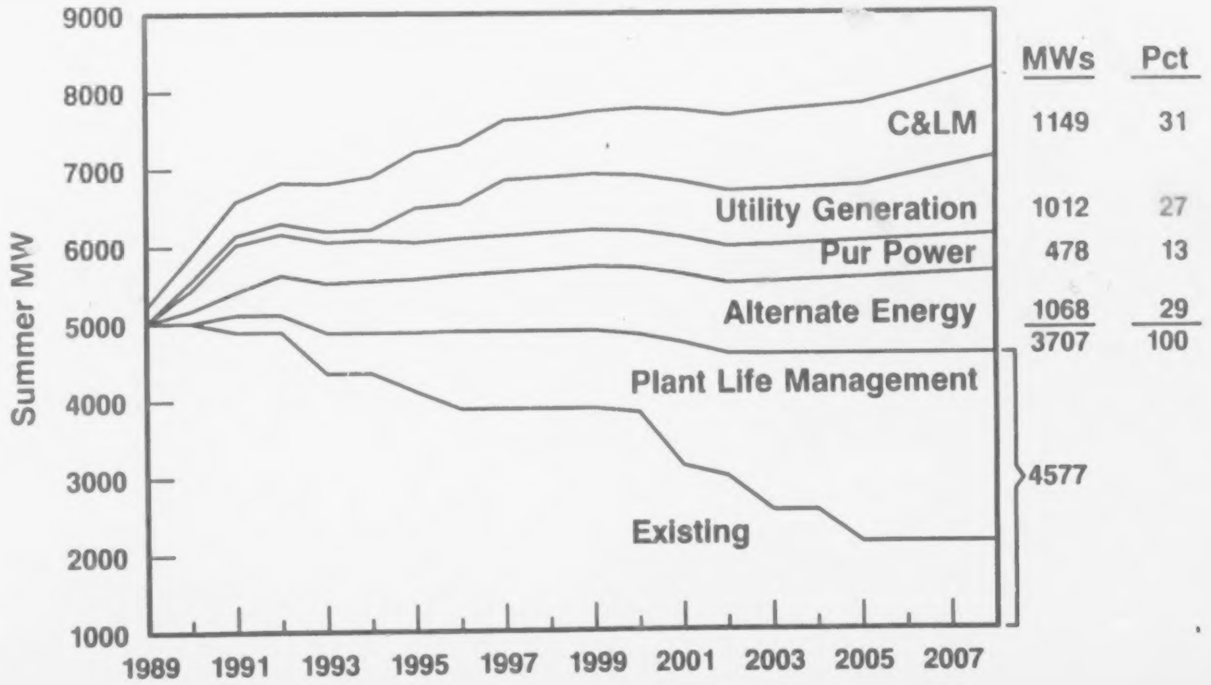


Figure 4

New England Electric System's
Conservation and Load Management Programs

COMMERCIAL AND INDUSTRIAL PROGRAMS

Performance Contracting Program

This program aims to maximize energy efficiency in facilities of large (500 kW+) Commercial and Industrial customers. Three energy services companies were selected through a competitive bidding process. These companies were contracted to promote load reduction by installing cost effective, electric C&LM measures on the premises of designated customers. Each energy service company has a list of customers which they alone may serve.

Incentives are paid to the energy service companies to promote installations that normally would not occur and to reduce the overall cost of installing electric energy-saving equipment.

Energy Initiative

Energy Initiative is a commercial and industrial energy management program designed to promote the direct installation of electric energy-efficiency measures in existing buildings. The Energy Initiative Program is available to any non-residential customer with an average monthly billing demand over 100 kW or average use of at least 20,000 kWh/month. Any of Massachusetts Electric's local, state or federal government customers are eligible to participate in the program, regardless of their size.

Design 2000

Design 2000 is a companion program to Energy Initiative that promotes energy efficient designs in new commercial (including multi-family residential), industrial and institutional buildings. Design 2000 provides incentives to developers, property owners, or general contractors for the installation of energy efficient electric measures. In many cases these incentives cover the additional cost of energy efficient electric measures over the building code or the prevailing practice.

Small C&I Program

The Small C&I Program is designed to encourage the installation of energy efficient lighting for customers with demand below 100 kW or annual energy use below 300,000 kWh. This program provides the customer with a no-cost lighting analysis, and installation of specific efficient lighting systems, including ballasts, efficient fluorescent and reduced wattage incandescent lamps, reflectors and occupancy sensors.

Interruptible Rates

Involves payments to customers who can reduce their demand on request during peak periods.

Standby Generation

Involves payment per kilowatthour to customers who agree to use their emergency standby generators when demand for electricity is greatest--during peak demand periods.

RESIDENTIAL PROGRAM

Electric Water Heater Rebate

Under the Water Heater Rebate Program an incentive is offered to wholesalers, retail dealers, plumbers, electricians, and contractors for the sale of energy-efficient electric water heaters installed in Massachusetts Electric's service territory. The incentive is based on the price differential between energy-efficient units and those that are traditionally sold.

Water Heater Rental

Through this program, only energy-efficient electric water heaters will be rented by the Company to residential customers.

Efficient Appliance "Blue Ribbon" Program

The Residential Efficient Appliance Program is designed to help residential customers become better informed about appliance efficiency, and to promote the purchasing of high efficiency models. Participating dealerships will display blue ribbon stickers on approximately the top 15 percent of efficient refrigerators, freezers, and room air conditioners. Customers will be able to obtain a brochure which discusses what to look for when buying an electric appliance at participating dealerships, as well as through a toll free number.

Dispatchable Load Control (DLC)

This program will offer customers the option of having their water heater turned off during times of peak demand in return for a credit on their monthly bill. A radio receiver attached to the house or complex will be activated by a signal generated by a centrally located computer. The receiver will then turn off the water heater for a predetermined amount of time. Customers typically experience no change in availability of hot water with the installation of the control.

Residential New Construction

This program will provide incentives to builders and developers for inclusion of energy efficient construction measures in electrically heated single and small multi-family buildings. The program will establish construction standards that exceed current building codes. As in the Design 2000 Program, incentives will be paid for electricity savings measured against a base line of current building code and practices.

Residential Space Heat

This program is targeted toward existing single and small multi-family dwellings that are heated with electricity. A comprehensive audit is conducted on the homes free of charge. The program also pays a portion of the costs to install recommended weatherization and other efficiency measures. Water heater wraps are also offered through this program, if one has not already been installed.

DEMAND SIDE BIDDING: THEORY VS. PRACTICE

Lydia M. Pastuszek, Director
Demand Planning
New England Power Service Company

The New England Electric System (NEES) Companies operate at the retail level in three New England states. Massachusetts Electric serves 903,000 customers in Massachusetts, Narragansett Electric serves 308,000 customers in Rhode Island and Granite State Electric serves 33,000 customers in New Hampshire. The system as a whole sells about 20 billion kWh annually, and most recently experienced a summer peak demand of 4134 MW. The System has experienced growth in sales of close to 5% on average since 1983. Sales by sector are balanced, with about 38% of total sales to residential customers, 35% to commercial customers, and 26% to industrial customers. The service area is characterized by low unemployment, growing wages, hi-tech industries, and a high quality of life.

The capacity situation in New England as a whole is very tight. NEES is a member of the New England Power Pool, which dispatches the electrical system and manages economy interchange. Delays in operation at one nuclear facility and prolonged outages at another nuclear facility, coupled with extraordinary growth in electric demand due to the strong underlying economy throughout the region, have resulted in tight operating conditions which will likely continue over the next three to five years.

Recognizing the important role that demand side programs can play in balancing resource needs, the NEES companies undertook a major demand side management program beginning in January 1987. The program has a short term goal of reducing capacity needs by 348 MW by 1991. By the year 2007, demand management programs are expected to contribute over 1000 MW to the resource mix, representing one third of new additions over the period (see Figure 1).

The NEES Companies have had a long history of activity in the demand side management area. In 1979, in its long range corporate plan, NEESPLAN, the System first enunciated its commitment to relying on conservation and load management to meeting resource needs. Since then, the System has sponsored leading edge research and demonstration projects in the demand side management area, and now is taking the lead in implementing these programs on a system-wide basis. Since these programs were first offered on system-wide basis in January 1987, the NEES Companies have achieved nearly 100 MW in demand reductions.

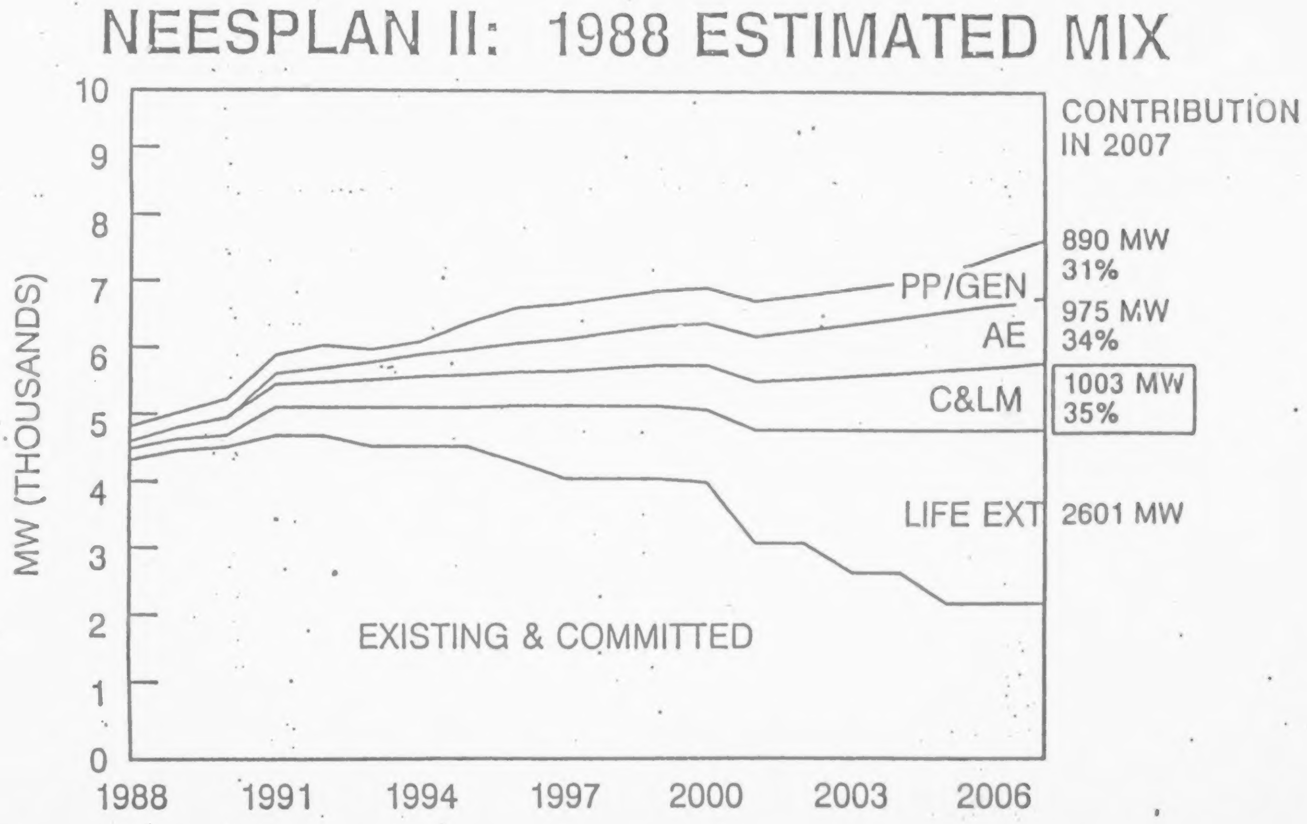
The NEES demand side programs are designed to provide incentives to our customers to use electricity more efficiently, particularly at times of highest production cost. The programs seek to encourage customers to reduce demand when the cost of that reduction is less than the cost of supplying the electricity (i.e., the avoided cost). Because costs of these programs will be covered through rates, NEES also seeks to implement programs that encourage efficient electricity use at the lowest possible cost in order to keep electricity rates as low as possible.

The System has experimented with several models of demand side bidding. In all cases, NEES has specified the classes of customers that are to be addressed by the bid and has defined the types of demand reductions that qualify, although very few restrictions have been placed on the types of measures.

Interest in bidding was first inspired by several rate orders issued by the Massachusetts Department of Public Utilities in cases involving other Massachusetts utilities. In 1985 the System began an experimental, multifaceted conservation program in 20 of its Massachusetts communities, called the Enterprise Zone. For large customers, 100 KW and over, demand side bidding was the cornerstone of the conservation program.

The Enterprise Zone Large C&I program was offered to 113 eligible customers. After conducting an audit at 96 of these customer facilities, 91 of the customers agreed to participate in a bid solicitation process. Customer billing histories and audit results were packaged and offered to third party performance contractors for bid. The Company offered to pay up to 7¢ per kWh for measured kWh savings over ten years. At this point in the program, only 21 customers received bids. Eight contracts were then successfully negotiated. As of this date, seven installations have been completed and one remains underway. (Many of the original 91 customers were served under another direct installation program

Figure 1:


NEESPLAN II: 1988 ESTIMATED MIX
MW (THOUSANDS)
0
1
2
3
4
5
6
7
8
9
10
1988
1991
1994
1997
2000
2003
2006
EXISTING & COMMITTED
LIFE EXT
C&LM
AE
PP/GEN
CONTRIBUTION IN 2007
890 MW 31%
975 MW 34%
1003 MW 35%
2601 MW

designed for customers under 100 kW in size.) About 90% of the estimated kWh savings derive from cogeneration, which was an accepted measure in the program. Figure 2 shows the participation results.*

In 1987, the System offered another demand side bid across its service area for customers over 500 kW in size. The service area was divided into roughly equal numbers of customers by geography and bids were solicited from energy service companies (ESCo's) in October. Insufficient bids were received to service all the customers system-wide, so the program was offered only in Massachusetts and another program implemented in the other two states. As a result of the bid, the System companies now have contracts for 13.6 MW in demand reductions with performance contractors in place. In turn, the participating contractors have signed contracts totalling 2.1 MW with customers. In this program, payments are not made over time but rather at the time of installation, based on estimated kW reductions. Under the terms of the contracts with the ESCo's, the demand reductions must be in place by April 1990.

By contrast, in the other portions of the service territory, a program called the Custom Program was initiated to serve commercial and industrial customers that could not be served by the bidding program contracts. Since its inception in May of 1988, this program has yielded 1.5 MW in demand reductions and 5.6 MW in future applications, a proportionately larger and faster response than from the bidding program. In the Customer Program, customers apply directly for incentive payments, and third party participation is not required. NEES is monitoring these two parallel programs closely to see which approach will yield the best performance.

In short, the NEES companies have seriously experimented with demand side bidding and have formed their perspective based on practical experience as well as theoretical objectives. While demand side bidding can, in theory, encourage innovation and competition in the delivery of demand side management, we do not think that bidding alone can deliver demand side management services effectively and quickly for a utility that is seriously in need of demand side management resources.

BIDDING CAN PROVIDE DIVERSITY

Bidding can enable innovation in the demand side management market. Certainly, the old adage of "two heads are better than one" applies here. Performance

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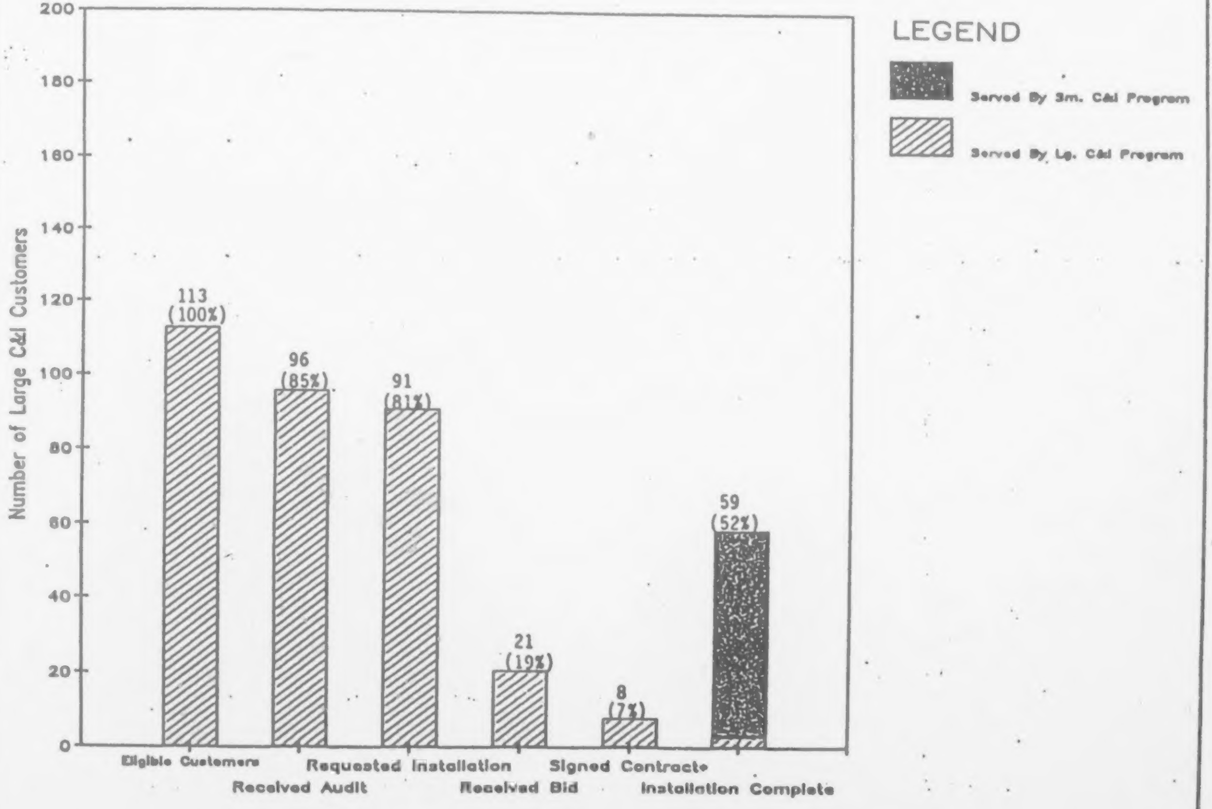
*A report, Evaluation Report on the Enterprise Zone, is available from the Demand Planning Department at New England Power Service Company for those who desire further information and details.

Figure 2: Participation in Large C&I Program



*In addition, one large C&I contract was signed and subsequently canceled contractors who devote full time energy and resources to developing conservation and load management resources are a valuable player in the market and can be a catalyst for moving customers into the installation of measures. The profit incentive is a strong motivating factor. Bidding programs which have the benefit of electric company sponsorship give performance contractors an edge to get in the door with customers. In the case of the NEES programs, our Conservation and Load Management staff often accompany the energy service companies on customer visits. This lends credibility and comfort to the customer. Thus, the energy service company becomes an effective marketing extension of the Company.

BIDDING MAY NOT PENETRATE THE MARKET

The market of third party energy service companies is not yet mature. It cannot deliver enough resources to serve all the needs at this time. There is an insufficient number of contractors doing business relative to the demand. This means that certain segments will be underserved.

Not all customers are willing to work with a third party vendor, nor can all customers work with a contractor selected through a bidding process other than their own (government buildings, for example). Other programs must be offered to assure that these customers are served.

Unless programs involving ESCo's are carefully designed and monitored, there is a risk that third parties will emphasize quick payback measures. Certainly utilities, because of their long term relationship with their customers, may be able to penetrate the market more quickly than can a third party. First, the utility has a deeper understanding of the customer's needs and can be viewed as more credible. Second, the anticipated ongoing relationship implies that the customer will trust the utility not to recommend measures that will create problems later on. Any program involving contractors must be closely monitored by the utility to ensure that customer satisfaction is not compromised. The degree to which a performance contractor's activities and installations can impact customer operations and hence satisfaction requires careful utility involvement at all stages of the process.

COMPETITION AND LEAST COST

Certainly, auction theory suggests that a bidding process will lead to more competition in price. But our current experience and data suggest that many demand side measures have costs well below the costs of even the most attractive supply side measures. A bidding process may ensure that the selected bid is the least costly of the bids reviewed, but it does not ensure that the selected bid is the least costly way to implement the demand reduction. This situation is further exacerbated by the fact that the number of vendors in the market is small relative to the demand, thus creating a lack of competition for the work.

DUPLICATION OF MEASUREMENT

Both the performance contractor and the utility will have to measure and monitor demand side management results; the utility, because it has to ensure that payments are appropriate and to measure actual savings, and the vendor because it has to ensure its investment level is appropriate. This leads to a duplication of costs that may be a necessary consequence of bidding programs.

INTEGRATION WITH OTHER PROGRAMS

Because the market is underserved by bidding alone, utilities must offer other programs in order to comprehensively reach all cost-effective demand side management. Thus, the utility must apportion the market among programs and be careful not to overlap segments or duplicate savings estimates. This means that the boundaries of any bid must be carefully specified in advance. While this is less of an issue at the outset of a demand side management effort because the potential market is broad, it could become more of a problem when a very active utility managed program and third party program could compete for the same market. Worst of all, this would be confusing to the customer.

OPEN RESOURCE AUCTIONS VS. INTEGRATED PLANNING

One appeal of demand side bidding is that it raises the stature of the programs so they can compete with supply resources. Most demand side programs should do very well in such a competition because they are significantly less costly than traditional and nontraditional supply resources.

However, the same result occurs if the utility planning process is integrated and considers supply and demand resources equally. In fact, the bid evaluation process and the integrated planning process should stem from the same assumptions. Since all utilities must do some sort of planning, it seems that an open resource auction is a poor substitute for the lack of a comprehensive planning process.

CONSIDERING CUSTOMER BEHAVIOR

A comprehensive utility planning approach that identifies the probable costs and penetration of customer conservation and load management actions prior to soliciting bids to provide those services has a distinct advantage because it considers the important element of customer behavior in identifying least cost opportunities. Specifically, such a planning process can identify:

1. Specific types and levels of cost-effective demand reductions;

2. Levels likely to occur without incentives (free-riders) and with incentives (program impacts); and

3. The likely costs of these demand reductions (including customer costs).

This process provides an essential benchmark against which to measure bids, if that approach is chosen, or with which to decide to implement a program directly by the utility.

Such as approach is essential because the element of customer behavior makes demand side programs different from supply side approaches. In the case of demand programs, a customer makes a conservation investment decision in response to the price of electricity, and through reduced bills, receives an incentive. The utility program then further encourages the customer to make an investment decision that meets the utility system's needs as well as the customer's needs. However, the utility program must take into account the natural incentive that affects customer behavior or else the utility may end up paying for conservation that would occur without any incentives, or pay more than is necessary to provide the incentive leading to behavioral change. In addition, if the incentive payment is high enough, it may lead customers to undertake inefficient investments.

The unique element of customer behavior complicates the bidding process, especially when one of the appealing features of such a process is its seeming simplicity. However, if the objective is a least cost resource mix, these complexities cannot be ignored.

CONCLUSION

The NEES Companies have experimented with demand side bidding because we want to encourage innovation in the market and because the importance of the demand side management resource is too large to eliminate a potentially vital segment of players. However, it would be a mistake to suggest that third party bidders alone could satisfy the demand in a timely, cost effective manner.

For the utility considering demand side bidding, there are a lot of lessons to be learned from our's and other utility experiences with bidding. Initiating a small scale demand side bidding experiment is an excellent way to get to know the vendors and the process itself.

We would hope that the regulatory process will recognize that flexibility is needed in offering demand side management programs and bids, while the market and utility experience in developing demand side resources matures.

Senator **Wirth**. Ms. Pastuszek, thank you very much.

Mr. Cohen.

STATEMENT OF ARMOND M. COHEN, SENIOR ATTORNEY, CONSERVATION LAW FOUNDATION OF NEW ENGLAND, INC.

Mr. **Cohen**. Thank you, Senator. I guess I wanted to share with you my perspective from the trenches, as it were, of the least cost planning debates. If I may be permitted a short story. I heard a definition of an economist as someone who looks at something working in practice and wonders whether it will work in theory.

Sometimes the least cost planning debate has that feel to me. I think we know what works. Let us get moving. My comments today are really directed in that spirit.

CLF has been working with eight utilities in New England to get things moving. Over the past couple of years, as some of the material attached to my testimony describes, we have been designing programs that will run about $200 million in total in 1990. If they continue on that trajectory, we should be up into about the $.5 billion range by the early 1990s. Those programs were also evolved through a unique process which is described in the attachments to my testimony.

I would like to take a moment to describe the nature of these programs so you can understand the comprehensive effort which I think could serve as a model nationwide. Under these programs, the utilities are not just putting bill stuffers into customer bills. They are not just doing energy audits. What they are doing, with New England Electric being foremost in this regard, is going to developers of new builders and saying we will pay you the full cost of building that building much more efficiently than the existing building code requires. In the case of existing buildings, NEES is going to the customer and saying we will pay whatever it takes to get high efficiency motor equipment, lighting equipment, ventilation equipment and the like installed in that building and will provide technical assistance and hands-on help to get it done.

These programs are very large. They are labor intensive. They involve large-scale monitoring so that some of the measurement questions that the Department of Energy and FERC witnesses raised can be settled once and for all. With New England Electric, as I also indicate in my testimony, we have developed an incentive plan which will provide NEES with a mark-up or a profit margin on the kilowatt hours it saves.

Together, I think these programs are really blazing trails nationally and internationally. Just this weekend I was attending a conference in Holland of the major nongovernmental environmental organizations in preparation for the ministerial conference that took place over the last two days. I can tell you that there is a great deal of interest in the New England programs among my Eastern Bloc colleagues as well as many of the delegates at that conference from the third world.

New England and the U.S., I think, have the potential to show some real leadership in this area. The problem before you is that it is not getting done except in some isolated cases where you have very progressive companies like New England Electric or very strong intervenors.

I think the national figures tell the story. On a national basis, I believe the $1 billion referred to by the EEI witness represents a very small fraction of what is being spent on power generation, new construction of transmission lines and power plants.

In New England alone, even though we are moving aggressively on conservation, the ratio between spending on new power plants versus conservation is still about 30 to 1, so there is a lot of distance still to go.

What I have suggested in my testimony is that S. 324 provides a nice start in this area, but I think more can be done. The proposal I lay out in my testimony is that the Federal Government can profit somewhat from the New England experience to date, mandate that utilities get active as the supplier of conservation of first resort, not the supplier of last resort, and that utilities nationwide begin to explore and develop the kinds of programs which are not being actively promoted by New England Electric and other utilities in New England.

The second part of my proposal is that a mechanism be provided by which there can be public involvement in the design, execution and monitoring of those programs. Again, this may be my cynical litigator's perspective from the trenches, but the debate on least cost planning has been going on ad infinitum, and unless there is a very strong public role in this or an exceptionally progressive utility like New England Electric, often these things just do not get off ground zero. I think that an intervenor funding provision as I have outlined in my testimony would provide a necessary spur.

The third proposal is that you leave out the no losers test. This is another issue that has been discussed ad nauseam. All of the New England commissions have rejected the no losers test as a test of cost effective investment. Many other utility commissions around the country have. Let us not go backwards on that issue.

My final point which is not in my testimony but may deserve attention by this committee or others is that very recently the IRS has set us back a step in conservation. There has been a ruling from one of the regional offices, I believe, that conservation investments by a utility are taxable income or can be construed as taxable income to the recipient of those conservation measures. I can provide more details to the committee staff.

That is sending out a very bad signal both to the conservation industry and to the utilities, and I suggest that there might be some attention to that either in this or other legislation.

In sum, the spirit of my comments is that least cost power planning is great. Let us get on to least cost power doing, which I think is the real challenge ahead of us. I think that this bill, while it provides a good foundation in this direction, might be stronger in that regard.

Thank you.

[The prepared statement of Mr. Cohen follows:]

CLF

Conservation Law Foundation of New England, Inc.

3 Joy Street
Boston, Massachusetts
02108-1497
(617) 742-2540
Fax: (617) 523-8019

TESTIMONY OF ARMOND COHEN

ON BEHALF OF THE

CONSERVATION LAW FOUNDATION OF NEW ENGLAND

BEFORE THE

UNITED STATES SENATE COMMITTEE ON

ENERGY AND NATURAL RESOURCES

HEARINGS ON S. 324
THE NATIONAL ENERGY POLICY ACT OF 1989

NOVEMBER 7, 1989

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Vermont Office: • 9 Bailey Avenue • Montpelier, VT 05602 • (802) 223-5992

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Mr. Chairman, Members of the Committee, and Staff:

My name is Armond M. Cohen, and I am a Senior Attorney with the Conservation Law Foundation of New England, Inc. (CLF). CLF is a non-profit environmental law organization representing several thousand members in the six New England states on a variety of issues of environmental concern, including global climate change and energy use. We appreciate the opportunity to present the Committee with our views on S. 324.

In general, CLF supports the electric power-related initiatives contained in S. 324 to ensure that energy efficiency investments are financially attractive to utilities, and to in some circumstances instruct utilities to purchase energy savings from non-utility vendors. Based on our concrete experience in New England, however, we believe these measures will prove inadequate by themselves to ensure the rapid and thorough acquisition of fossil fuel-displacing energy efficiency improvements. CLF's chief recommendation is that S. 324 be modified to provide in more detail for a more direct utility role in energy efficiency improvements.

Introduction: The New England Model

The notion that large scale energy efficiency investments by the electrical utility sector can be a major policy tool in combating climate change is beginning to be proven on a grand scale at present in New England. Over the past 18 months, CLF has been working cooperatively with eight electric companies in New England (representing about three quarters of the region's electric demand) to develop, implement, and monitor aggressive electricity efficiency investment programs. This unique cooperative effort, in which the utilities are funding CLF's key energy experts to work and negotiate with company staffs, evolved as a sensible alternative to endless litigation over how much energy efficiency is available to meet New England's electric needs and avert unnecessary environmental damage. CLF's joint work with the utilities is described in Exhibits 1, 2, and 3 to my testimony.

In the programs being designed by the utilities and CLF, the utilities will directly install and pay for high-efficiency lighting, heating, insulation, ventilation and motor and process equipment in New England's homes, businesses and industries in both existing and new construction; the utilities will also assist customers to improve the energy efficiency of customer operating and maintenance practices. One of these cooperatively designed programs is described in some detail in the document "Power by Design," attached to the testimony of my co-panelist, Ms. Lydia Pastuszek.

The major ground-breaking feature of the New England programs, which distinguishes them from current and previous utility-sponsored programs elsewhere in the nation, is that they provide "soup to nuts" management and in most cases full financing by the utility of the energy efficiency improvements. For the most part, these utility efforts are not equipment "rebate" programs, or "energy audits," or bill stuffer programs. Instead, they represent serious, large-scale, hands-on deployment of engineering finesse and hardware to bring down power consumption dramatically in new and existing buildings and factories while providing the same or better light, heat, and motor drive. The utilities have committed in effect to building and maintaining a large scale "efficiency power plant" for whose reliability and performance they take the primary responsibility.

In addition, with New England Electric, CLF has developed one of the first detailed proposals in the nation that would allow an electric utility to earn a better return on saving than selling energy. That proposal, described schematically in Exhibit 4 to my testimony and now pending before regulators in Rhode Island and Massachusetts, will, if approved, provide an example nationwide.

Through such programs, the eight utilities with which CLF is working will spend approximately $200 million on energy efficiency in 1990 alone, the first full start-up year of the programs -- a four-fold increase from the previous year. By 1992, we expect electrical conservation spending by these utilities to be in at least the $500 million dollar per annum range, or close to 10% of the companies' annual gross revenues. CLF estimates that these kind of investments could keep current fossil fuel use for power generation in New England at constant or even declining levels over the next 20 years, even in the face of robust economic and demographic growth. These investments will also displace the need for new power sources costing twice or three times the price of efficiency -- providing enormous economic as well as environmental benefits.

The New England programs have received international attention, and the data that emerge from them will be key in guiding energy policy-related responses to global warming.

Specific Comments on S. 324

On the basis of this experience, I would submit that this Committee, in its search for federal policy to stimulate utility investment to mitigate climatic change, might be wise to use as its guiding criterion: "How can Congress make what is happening in New England happen elsewhere in the United States?"

CLF believes that the current version of S. 324 contains some important advances in this direction. We would like to offer, however, some specific recommendations to make the legislation more effective in achieving its purpose:

1. S. 324 Should Be Modified to Require Electric Utilities Themselves to Implement Programs to Improve Customers' Electrical Efficiency And Not Merely to Respond to Third Party Offers to Do So.

It is no accident that the emerging New England programs rely -- at least for the next several years -- on the utilities as the major planners, investors, and supervisors of energy efficiency improvements. This approach, in CLF's view, is essential for the near-term, given the enormous market barriers to energy efficiency and the utilities' unique advantages in overcoming these barriers. It is worth mentioning some of these real-world barriers, especially since there has been some suggestion in both academia and elsewhere that the way to elicit the optimal level of energy efficiency improvements is simply to require electric utilities to buy efficiency from any third-party vendor who claims to be able to deliver saved kilowatt hours less expensively than the utility or a non-utility entity can generate kilowatt hours.

Our research and program experience in New England suggests that this is not so, for two principal reasons: 1) the gap between the social and purely entrepreneurial perspective, combined with data gaps on efficient technology and design and building performance (which, together, constitute the "cream skimming" problem); and 2) infrastructure barriers.

a. Cream-Skimming

The essence of the utility monopoly franchise is the obligation to serve its customers reliably and at reasonable cost. In many states, particularly in New England, this obligation has been further defined to include the provision of reliable energy services (including energy savings, where less costly than raw kilowatt hours) at least cost. Presumably the objective of S. 324 is to create even greater emphasis on the energy savings part of the equation, recognizing the national and international imperative to achieve as much energy efficiency as is economically feasible.

Third-party providers of energy services have no such overriding social objective, at least not one for which they can be held to legal account. Their objective, understandably, is to maximize profit. This is not a bad thing and, indeed, as I will suggest in a moment, this entrepreneurial motivation, if harnessed correctly, can add greatly to the innovativeness and success of the energy efficiency effort.

The problem, however, is one of quality control. Energy savings packages are not quite fungible in the way that kilowatt hours are. One can tap energy efficiency in a home or facility thoroughly, by replacing inefficient lighting with high frequency ballasts, low-wattage tubes, reflectors, dimmers, and daylighting techniques; by downsizing oversized chillers; by installing electronic motor controls; by making high quality insulation improvements; and, in the case of industry, by reconfiguring the underlying manufacturing process itself to reduce energy requirements. One can also tap energy in a home or facility superficially, by, say, merely weatherstripping, or installing only low-wattage bulbs, and ignoring the rest. In short, one can milk the full potential for energy efficiency, or simply "skim the cream."

The evidence to date is that, without aggressive utility supervision of efficiency investments in facilities, the tendency of third-party providers has been to skim the cream, to maximize short term profit at the expense of deep savings.[1] Many are the instances in which "performance contractors" have touched nothing but the two or three cheapest efficiency measures, and done so in a non-workmanlike manner. This results in both economic inefficiencies (it is costly to once again incur overhead to do further retrofits at a later point in time) and obvious environmental lost opportunities.

The problem in compounded by the absence of uniform "off the shelf" retrofit or new building design which can simply be put "out to bid." There are still uncertainties about the performance of some technologies, and about the optimal techniques to design or retrofit heating, cooling, lighting, motor, and ventilation systems. In short, the energy efficiency field is still something of a developing industry, making it hard to be confident that efficiency designs and installations will push the envelope of technical potential without a strong utility role and the design and installation process. This problem will no doubt be resolved as industry standards are better developed and the experience base grows. At present, however, neither of those conditions are present.

b. Infrastructure Barriers

A major condition of utilizing energy efficiency as a tool to combat global warming is that efficiency improvements be readily and widely accepted by customers. Yet a recent independent analysis reviewing the existing energy service market in the Boston area concluded that utility customers are in general distrustful of the competing claims of energy service firms, particularly where business operations could be disrupted from faulty or faultily installed equipment.[2] Analysis by CLF program experts indicate that, by contrast, businesses and homeowners are more likely to cooperate in a utility-managed project; the utility, at least, is likely to be around and financially solvent in the event things don't work out. Utilities also have the advantage of an existing service infrastructure for marketing to its customer base, an infrastructure which can be harnessed to promote energy savings.

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[1] One example in the residential sector can be found in H.G. Peach, evaluation of performance contracting program for Northeast Utilities (1989). [Specific reference available upon request].

These advantages are being borne out by the early results of some of the CLF/utility-designed programs in New England. For example, after only one year of operations, Northeast Utilities' program to upgrade the energy efficiency of new commercial and industrial facilities at least 20% above standard practice and code requirements has achieved the participation of fully a third of all newly built floor space in the utility's Connecticut service territory.

None of this is, of course, meant to suggest that energy service providers have no place in advancing the efficiency agenda; they do. Indeed, the lion's share of the $200 million of efficiency investment to be made in 1990 in New England will flow to private equipment vendors, installers and energy service companies. By competing for the actual implementation of the utility programs, this market will grow and innovate, bringing costs down.

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[2] Putnam, Hayes & Bartlett, "Supporting Documents on Conservation and Load Management Prepared for the Boston Edison Review Panel" (March 1987) at page 16-18.

But, on the basis of the factors described above, CLF believes it would be unwise to assume that such firms by themselves can accomplish the task ahead at this time, without the framework of a well-designed utility program. What is needed instead a strong utility pump-priming effort for the foreseeable future to develop the market, push the technical edge of energy efficiency, and establish standards within which a more decentralized provider market can ultimately operate.

Therefore, CLF recommends that Congress establish a baseline requirement for utility-driven programs to improve energy efficiency, allowing PURPA-type competition where the utility has failed to fulfill its task. Specifically, S. 324 should be modified to specify the minimum criteria for adequate utility energy efficiency programs. These criteria need not be extensive, and their detail could be left to rulemaking at the state or federal level, but they should provide a minimum acceptable baseline. Successful program activity in New England can inform the development of these criteria. At a minimum they would include requirements:

o that each utility field a program of financial and technical assistance to developers of new residential, commercial and industrial floorspace more electrically efficient than otherwise required by applicable building code or practice;

o that each utility provide a similar program for retrofit of existing buildings and industrial processes;

o that each of these programs offer sufficient financial incentives and technical assistance to ensure that the maximum feasible and cost-effective level of demand reduction is achieved, taking into account externalities such as environmental costs;

o that utilities be required to accept competitive bids to supply the direct energy design, installation, and monitoring services provided for within the program;

o that each utility provide an adequate program to measure reliably the demand reductions resulting from these programs; and

o that, where a utility fails to have in place programs meeting the above criteria by a reasonable date certain, the utility must finance third-party providers to carry out efficiency investments in its service territory.

2. The Committee Should Reject The Discredited "No Losers" Test.

To the extent PURPA is amended to allow qualifying conservation entities to compete, the price should be exactly as established on the supply side -- the full incremental cost of avoided energy. By allowing states the option to cap payments at the difference between avoided cost and average price, the current version of S. 324 would seriously handicap energy efficiency.

While internal distributional effects of targeted efficiency programs are worth reckoning with, it must be recognized that similar distributional issues infect the acquisition of major new supply resources (e.g. well-heeled industrial customers may flee to self-generation to avoid plant-related price hikes, leaving captive residential and small commercial ratepayers to absorb a larger share of system fixed costs). Moreover, inter-class and inter-customer cross-subsidies can be moderated through careful attention to providing broad programs, along the lines suggested above.

At bottom, society should seek to minimize its overall cost of energy services (including external environmental impacts), not specific near-term rates. Title III, Section 313(a) of S. 324 would frustrate that goal.

For a definitive discussion of this issue, CLF invites the Committee to review the Proposed Order in current Vermont Public Service Board Docket 5270 (1989).

3. The Committee Should Consider Providing Intervenor Funding for Intervention in State Utility Proceedings and Collaborative Negotiations Related to Utility Provisions of the Bill

As Exhibits 1, 2 and 3 demonstrate, CLF, a non-profit intervenor, played a crucial role in moving the energy efficiency agenda forward in New England. Nor should it be surprising that independent non-governmental institutions may have to continue to play a role in the regulatory process to help reform utility practices. In our experience, however, few similar organizations in the nation have the resources or internal staff capability to intervene so vigorously and persistently. If, as S. 324 reflects, the actual policing of utility activity pursuant to new federal mandates in the energy efficiency area is still to reside at the state level, the public interest would be well served by allowing for active public involvement with adequate resources.

The bill should explicitly provide for compensation for attorneys' and expert witness fees where intervenors make a substantial contribution in contested matters under the act. The bill should also provide for utility funding of qualified intervenor groups in the kind of collaborative energy efficiency program design negotiations described in Exhibits 1, 2 and 3.

Conclusion

CLF again appreciates the opportunity to comment on S. 324, and looks forward to answering questions from the Committee.

EXHIBIT 1

PROFILES

The Power Brokers

Once considered an "outsider and meddler," the Conservation Law Foundation of New England is now setting the utilities' agenda

Dick Russell

Probably no region of the country has been so embroiled in the question of how-to-power as New England. The economy is booming and population rapidly rising; electrical shortages and brownouts compete for equal time with antinuclear activists who want to make sure that Massachusetts's Pilgrim plant stays closed and that New Hampshire's $5.3-billion Seabrook never opens. Meantime, politicians and utility executives talk up expensive new projects to connect with coal-fired plants in Nova Scotia or West Virginia.

The multibillion-dollar dilemma touches the lives of everyone in the six-state, eighty-eight-utility New England area, and is echoed in varying degrees across the nation. The irony is that both the intellectual and pragmatic breakthroughs are coming not from the utility industry, but from the Conservation Law Foundation of New England (CLF), a Boston-based environmental group whose legal challenges to nuclear power were long accused of exacerbating the power crunch.

CLF has embarked on what it hopes will be an unprecedented application of energy conservation concepts pioneered in the West by the likes of Amory Lovins, Arthur Rosenfeld, and NRDC's Ralph Cavanagh. [*See "The Rise and Fall of Energy Conservation," Spring 87.*]

The notion is that the utilities should invest in conservation measures themselves: not their customary pittance, but as much money as they otherwise would pour into new power facilities.

"Consider the Copley Place development over there that went up a couple of years ago," CLF's executive director, Douglas Foy, said recently on a blistering summer afternoon, pointing a long finger out the window of his office. "That's a twenty-five-megawatt building, which is as much electricity as the whole suburb of Chelsea uses, and it's incredibly inefficient. But what if Boston Edison had gone to the developer and offered to pay the cost of installing better equipment? Why, they'd have had a much more marketable building because it's cheaper to run."

Foy, now forty-one, is the son of a senior executive with Jersey Central Power and Light. A member of the U.S. Olympic rowing team in 1968, originally he had intended to become an electrical engineer. But the energetic, tough-minded young idealist instead entered Harvard Law School, and in 1975, after a few years' practice with a downtown Boston firm, came to CLF.

Until his arrival, the small organization founded in 1966 had concerned itself primarily with preserving open space. Today CLF has grown to some twenty-three staff lawyers, scientists, and administrators, and a 1988 budget of $1.3 million. About half that money comes from some 7,000 dues-paying members, and the rest from such foundations as Alton Jones, Merck, and the Educational Foundation of America.

CLF's lawsuits have stopped the first three attempts (and are challenging a fourth) by the U.S. Department of the Interior to allow offshore oil drilling at the Georges Bank fishing grounds. They have forced long-delayed action on the cleanup of Boston Harbor, and defeated a U.S. Forest Service plan to double timbering and build 260 miles of new roads in New Hampshire's White Mountains, New England's largest remaining wilderness. Legislation drafted by CLF and enacted by Massachusetts in 1987 is the country's strongest for preventing lead poisoning of children. This year, the group has sued Massachusetts for failing to reduce its ozone smog to safe levels as mandated by the federal Clean Air Act.

"They've become without question the preeminent environmental legal group in New England," says Michael Deland, the regional administrator for the U.S. Environmental Protection Agency, "and perform an extremely valuable role as an aggressive and tenacious watchdog."

Deland, who has been on the federal government's side against CLF in courtroom battles over Boston and New Bedford harbors, holds no grudges. Indeed, he adds, "The times when we've been sued by CLF, I felt that we'd been constrained by either statute or regu-

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Dick Russell *is a free-lance writer in Roxbury, Massachusetts, and the recent recipient of a Chevron Conservation Award.*

lations. The regulatory agencies tend to be positioned somewhere between the environmental activists and the industry lobbyists, and here in Region I, I'd like to think we're much closer to the former. Hence, the lawsuits were welcomed by me personally."

Much the same sentiment is echoed by Sue Tierney, commissioner of the Massachusetts Department of Public Utilities (DPU), which governs private utilities' investments and rate hikes. "The DPU has been on record in a number of cases over the past couple years, deciding that it's in the public interest for utility companies to invest in cost-effective conservation programs as part of their supply strategies," Tierney says. "But not much progress was being made beyond a lot of discussions and proposals. When CLF intervened in a rule-making case, proposing to go beyond adversarial positions and work with the companies to try to find an expeditious solution, our commission ultimately said in August—we're delighted!"

Evolving from foe to collaborator has not been easy for either CLF or the utilities. The two first locked horns in the early eighties in the battle over Seabrook II, the second of a pair of giant twin reactors being jointly built by sixteen New England utilities. CLF set out to block it as an economic lemon. After intervening in a dozen commission proceedings in four states, offering testimony that the Public Services Company of New Hampshire (PSNH) labeled "informational terrorism," CLF succeeded in obtaining commission orders that forced the Connecticut and Maine utilities to bow out of backing the second reactor. (CLF also predicted a debt spiral that eventually would force PSNH, majority owner of Seabrook, into bankruptcy. This year that prophesy came true, as the cost of completing Seabrook I alone escalated into the billions.)

Opposite: CLF gathers in a Boston courthouse where many of its suits are heard. In the foreground are Armond Cohen (l.) and Doug Foy. (Stephen O. Muskie)

"Part of our case required us to show that there were alternatives to Seabrook," Foy recalls. "So we started to develop a conservation analysis with a series of witnesses." The Big A case in Maine in 1986 honed CLF's arguments.

The Great Northern Paper Company had wanted to build a huge dam to meet its energy needs and stay competitive with Canadian manufacturers. But the location for the Big A was the West Branch of the Penobscot River, a haven for white-water rafting and salmon fishing. CLF flew in Amory Lovins, director of the Rocky Mountain Institute in Colorado and the nation's leading marketer of energy conservation. By using fourteen different ways to make its motors more efficient, Lovins told the Maine Public Utility Commission, Great Northern Paper could save as much power as the forty-megawatt dam would provide at about one-fifth the cost. Eventually, the Big A bit the bullet.

Evolving from foe to collaborator has not been easy for either CLF or the utilities.

In December 1986, the New England Governors' Conference called for a regionwide effort to identify the least expensive way of supplying power over the next two decades. In response, CLF organized a twenty-six-member Energy Policy Council (EPC), including every environmental and consumer organization in the area that participated actively in energy matters.

Around the same time, the Boston Edison Company came under fire from DPU, which accused it of gross mismanagement and imposed financial penalties. What Foy calls "the most scathing commission order I've ever seen" was sent to every Edison board member, including ex-Massachusetts Senator Paul Tsongas, who advised the company to appoint an outside panel to review its affairs. Foy, in his words "the token environmental guy," was one of three men asked to prepare the report, who were able to "take Edison's money and spend it on some very high-class utility analysts," including Lovins. In March 1987, the Edison review crew not only concurred with the commission's findings, but proposed direct utility investment in the notion of a "conservation power plant."

As detailed in "Power to Spare," a CLF/EPC report, the rationale went like this. New England already spends over $7 billion a year for electricity, reflecting utility rates that are 25 percent higher than the national average. Most of that electricity is used by industries and commercial facilities (such as offices, stores, hospitals, and schools), which comprise only 10 percent of all customers. And it goes predominantly for a few basic needs such as lighting, industrial motors, and space conditioning. According to the report:

> Building more power plants will take a tremendous toll on New England's environment. New England's coal and oil-fired plants already emit over half a million tons per year of sulfur dioxide and nitrogen oxides, the major causes of acid rain, while New England's nuclear plants produce 200-250 metric tons a year of high level radioactive waste. Trash-burning and wood-fired plants emit toxic compounds such as dioxin and acid gases. In addition, lacing the region with new power plants and transmission lines would dramatically lower the quality of our already threatened landscape.

Using available technologies for high-efficiency lighting, motors, insulation, air conditioning and other appliances, the region could reduce its electricity needs by 35 to 57 percent over the next twenty years through efficiency improvements—at far less cost to both utilities and consumers than build-

The Boston Edison (BECo) Review Panel and BECo board member, former Senator Paul Tsongas, report its findings at a press conference. The panel found "a pattern of recalcitrant policies" towards regulators; a lack of effort or commitment to conservation and energy alternatives; and a record well behind that of more successful and enlightened utility companies. From left: Bernard Cherry, president of a geothermal energy company; William Hogan, a utility expert on the faculty of Harvard's Kennedy School of Government; Tsongas; and Doug Foy.

The Boston Globe

ing new power plants. In Massachusetts, for example, installing such conservation devices would save an amount of electricity equivalent to the production of four mid-sized coal, gas or nuclear plants by the year 2000. Compared with nine to ten cents per kilowatt-hour for new plants, the cost of a massive conservation effort was estimated between 2.8 and 5 cents.

Armond Cohen, a whiz kid who came to CLF directly from Harvard Law School in 1984 and coauthored "Power to Spare," notes, "Increasingly, environmental groups find themselves in the role of being almost free-lance planners. Our old style of energy case law was just to intervene and block the goddamned plant. Now we're realizing you have to step back, do some of the bureaucracy's thinking for it, try to really lay out the vision."

Foy points out that besides being dominated by electrical engineers trained to solve demand problems with more generation, "The companies haven't had people who really knew the state of the technology. The efficiency markets are changing very much like the personal computer markets have over the past decade. Every year or so, what's available in new lighting systems and refrigeration equipment now makes the old obsolete. But the utilities were convinced that conservation was up to the customer. They've been playing marketing games forever, putting little stuffers in our bills telling us to buy certain light bulbs and they'll give us a little money as a rebate."

Last November, CLF jumped into a case where Connecticut Light & Power was seeking a rate increase before its state commission. The utility executives balked at CLF's proposal, saying it already had excess capacity that added efficiency measures would only increase. They wanted less conservation, not more.

While Cohen prepared the legal briefs, CLF enlisted NRDC's Ralph Cavanagh, the prime mover behind Oregon's pioneering Hood River Conservation Project. [*See Amicus, Summer 1987*] He steered CLF to Tom Foley of the Northwest Power Planning Council; Gil Peach, former director of the Hood River Conservation Projtect; and Arthur Rosenfeld of the Lawrence Berkeley Laboratory, a leading consultant for the U.S. Department of Energy, whose efficiency ideas had pushed California into the forefront of conservation.

"If we'd tried to do this from scratch, it probably would have been impossible to make happen," says Joseph Chaisson, a CLF energy consultant from Maine. "But we were able to tell the Connecticut commission, look, these things have already been tried and they've worked. Plus, our witnesses laid out a direction that had such commonsense logic to it, it just transcended all the number crunching and name-calling."

Like Connecticut, they noted, the Northwest also had a massive power surplus, but that did not preclude conserving for a less certain future. The programs were eminently doable. The utility countered by trying to dismiss Hood River as only a pilot project, and its consulting firm purported to show that conservation in the Northeast could not work because citizens had not responded in the past.

Combat before the commission lasted two months. In early February, it declared that "the time for further study and pilot programs has ended," and handed down its order: double expenditures on efficiency, get together with CLF, come up with a direct investment program, and do it fast.

> The Connecticut conservation plan filed last May intends to cut in half the anticipated growth in demand for electricity.

Northeast Utilities put up $200,000 to pay CLF's consultants to work with its own staff. The collaboration was overseen by Chaisson, whose background had been more in land-use planning and telecommunications policy before he ran into CLF in the Big A case. Even critics say that Chaisson was a marvelous diplomat with lawyerly skills, able to boil down extremely complicated information into commonsense approaches. Above all, he realized it was as much a matter of "human management" and overcoming long-standing institutional barriers as of coming up with the right technical answers. Tensions rapidly defused, and the new alliance "worked weekend after weekend and late into the night," according to Cohen. Behind the scenes, keeping the company's top brass up-to-date (and at arm's-length from the planners), was Foy. As viewed by John Cagnetta, Northeast Utilities' senior vice-president for corporate planning and regulatory relations, "Doug Foy and his associates have developed some unique capabilities in creating an environment where discussions don't become polarized."

The Connecticut conservation plan filed last May intends to cut in half the anticipated growth in demand for electricity. In addition to free installation of weather stripping and longer-lived light bulbs, Northeast Utilities will conduct free energy audits for houses, apartments, and factories and contribute toward the cost of insulation. Besides paying for engineering studies to modify older commercial buildings, it will provide design assistance for new developments and pay the extra costs of high-efficiency equipment.

The $20 million the company will spend over the next year on conservation will result in an "avoided cost" of about six cents per kilowatt-hour, by displacing power generators, according to Chairman William Ellis. Changes in a single new building of 60,000 square feet or more could save as much as 15 million kilowatt-hours over the life of the equipment: enough electricity to power 2,500 homes for a year. The company will recoup its costs through higher rates and, if conservation increases its spare capacity, it can sell the extra power to neighboring utilities at a profit.

After Massachusetts DPU ordered a coalition of utilities to work with CLF, in July they unveiled their agreement to pay $385,000 over the next year to CLF consultants to adapt state-of-the-art energy-saving programs. If, as CLF and EPC are shooting for, the companies end up putting out about $2 billion over the next ten years, the anticipated savings of over 2,000 megawatts would be equivalent to two Seabrooks. Watching this process unfold from Colorado, Lovins marvels, "CLF is now even exploiting interservice rivalry between some of the utilities over who can get the most credit for the best efficiency program."

Recently, Foy and Cohen sat huddled in a CLF conference room, plotting how to take on Vermont and Maine in their ongoing energy revolution. Although the suppliers of about 80 percent of New England's electricity are well onto the bandwagon, the Maine utilities proposed a massive purchase of power from Hydro Quebec, a plan opposed by both CLF and the Natural Resources Council of Maine. Partly as a result of CLF's arguments, in early January, Maine turned down the utilities' proposal, noting that cheaper conservation options had not been explored adequately.

> "In the next few years New England utilities will take over undisputed leadership in conservation efforts."

Reflecting on their recent accomplishments, Foy and Cohen believe that both the regulators and the regulated are coming to the view "that energy services is the business that electric utilities are in, not supplying kilowatt-hours." And everybody benefits: utilities, consumers, labor, and the environment.

Cavanagh predicts that "in the next few years, the New England utilities will take over undisputed leadership in conservation efforts. And CLF is the big part of that reason." Already New York and New Jersey have expressed interest in CLF's work, and Foy is not ruling out a pitch to other utility commissions across the country. "Here we are, within less than a year's time, targeting programs that will spend literally hundreds of millions on improved efficiency over the next few years. It's become a tidal wave."

Across New England, the powers-that-power would find it hard to argue with that. ☐

EXHIBIT 4

The Collaborative Process in Utility Resource Planning

By WILLIAM B. ELLIS

A major investor-owned electric utility in New England has embarked upon a distinct new process for developing programs to enhance energy conservation in its service area and load management on its distribution system. A number of specialists not affiliated with the utility now participate in the design and implementation of such programs, thus the term "collaborative process." In this article, the chief executive officer of the utility company tells how this new process came about and what it has accomplished to date.

There is a growing sense of the value that utility companies can add to the service they provide to their customers. The so-called "value added" component of service can be, probably should be, and for Northeast Utilities (NU) is, an important factor in a strategy to remain competitive.

According to a carefully constructed recent survey by Cambridge Reports, customers place a value on those extra services, and are less likely to be concerned about rate increases when they feel that the service they are getting goes beyond the delivery of kilowatt-hours. Customers don't buy kilowatt-hours and put them on the shelf and say aren't they nice. They buy comfort, they buy heat, cooling and light, and ventilation and refrigeration. And they care less about the unit cost if they perceive that we care about their needs and do things to help provide for those needs in the most efficient way.

William B. Ellis is chairman and chief executive officer of Northeast Utilities, a holding company whose principal subsidiaries are The Connecticut Light and Power Company, Western Massachusetts Electric Company, Holyoke Water Power Company, Northeast Utilities Service Company, and Northeast Nuclear Energy Company. He is also chairman of the Connecticut Yankee Atomic Power Company and a member of the executive committee of the New England Power Pool. **Mr. Ellis** holds a BS degree from Carnegie-Mellon University and a PhD degree from the University of Maryland, both in chemical engineering.

Many utilities are faced with competition the likes of which they haven't seen in 50 years. And it's easy to understand the view that fixed costs have to be covered by spreading them out over sales, and that rates have to climb if sales fall.

But unless revenues are eroded faster than the service-area economy is growing, fixed costs are being spread over more sales. Furthermore, many utilities are not in a construction mode, so fixed costs may be falling because of depreciation.

Conservation as a Resource

In a growth area such as New England, conservation can be a major part of a utility company's resource picture for meeting both utility and customer needs.

Utilities may be mandated by federal or state regulatory agencies to pursue conservation programs, or they may do so for other reasons such as strengthening customer service, fulfilling a special responsibility to the disadvantaged, meeting competition from other power resources like self-generation through increasing customer satisfaction, and solving capacity shortages that can be short-term, long-term, or immediate.

Regardless of the motivation along this continuum from externally imposed reasons to strong and immediate internal business reasons, legislators, regulators, and advocates are exercising a growing influence over the manner in which a utility's energy efficiency strategy is carried out.

The main opportunity for policymakers to influence conservation is afforded in rate cases through comment on utility operations which might affect the utility's bottom line. Opponents to the new rate typically presume the increase might have been less had demand and consumption been lowered. Where demand is growing and a utility supply situation may require additional power plants or purchases of power, energy efficiency is often posed as a most cost-effective (least cost) alternative.

The concept makes sense but the public-private discussion of such ideas in the rate case context results in adversarial relationships.

A More Inclusive Planning Process

Only recently have the first successful attempts been made in Connecticut and Massachusetts to pursue an alternative method of including ideas of consumer groups into the utility planning process, that replaces the volatile rate case forum.

A key organization involved in cases in both Connecticut and Massachusetts is the Conservation Law Foundation of New England (CLF). This organization and its consultants from around the country intervened in a Connecticut rate case, pointing out that more aggressive investment should be pursued as a corporate strategy for offsetting the need for future power supplies. It was also noted that there remained significant portions of the consumer population that were yet unserved (or underserved) by the company's broad-based programs.

New England was spending more than $7 billion a year for electricity, reflecting rates that were 25 percent higher than the national average. Industry and commerce, comprising only 10 percent of all customers, used practically 50 percent of this energy to heat, light, air-condition, ventilate, and motorize factories, offices, stores, hospitals, and schools. The CLF reasoned that the region could reduce its electricity needs by 35 percent to 57 percent over the next 20 years through high-efficiency lighting, motors, HVAC systems, and insulation. And the cost, it said, would be far less than investing in new power plants. The cost of a massive conservation project was estimated at or less than six cents per kilowatt-hour, compared with eight to 9.5 cents for new plants.

While many of the points being made by the outside interested parties in these rate cases were certainly worthy of further consideration, their discussion in the rate case hearing rooms seriously interfered with the main business at hand. Such issues came to be viewed as counterproductive by most participants, including the commissioners and their hearing officers, because issues were seldom resolved in such imposing settings.

However, the company acknowledged that the experience and ideas of these intervening parties could be valuable in helping to shape NU's previous sincere efforts at a significant demand management program.

In early February 1988, Connecticut regulators issued a ruling within the context of NU's rate case calling on the company to greatly expand its efforts.

A New Beginning

In an unprecedented show of cooperation between regulators and a major utility, it was concluded that NU would work with representatives of the intervening parties outside of a rate hearing process to review its conservation and load management programs, to develop new plans, and to modify old ones where needed.

This would be done in a collaborative manner with NU's conservation and load management staff and consultants of the CLF, attorneys general, consumer counsels, and other offices and agencies in the two states — parties which, quite frankly, had criticized us rather significantly for not addressing the right markets, losing opportunities for conservation, and in general not having enough programs out there to meet the needs of certain segments of our customer population.

The first collaborative process began in Connecticut in February 1988, and was followed by a multi-utility process in Massachusetts of which Western Massachusetts Electric Company is a member.

Key among the benefits of the collaborative process was the potential to reduce dramatically the burden some amount of conservation and load management litigation in future rate cases and to limit the focus to essential issues. This promise alone would save the utility significant sums in paperwork, cross-examination and time in these future cases.

Top management at NU limited its involvement to oversight activities throughout the collaborative planning conducted by the company in both states. Allowing the process thus to follow a "grass roots" approach proved successful at uncovering a great amount of planning information and at fostering maximum creativity.

Funding the Process

But before all sides could gather to resolve issues tha wouldn't yield in the hearing room, a meeting was held involving NU's top management along with the Connecticut consumer counsel, the state Under Secretary for Energy in the Office of Policy and Management, and Douglas I. Foy, executive director of the CLF.

Out of that meeting came an unprecedented commitment by NU to provide $250,000 to fund the costs o research and data-gathering by experts working for intervenors and interested parties. This financial commitment proved to be the turning point in the proces because the intervenors lacked the funds needed to ge engineers and technical people together to help desig the energy conservation program. Had NU not agree to put the money on the table, the negotiations likel would not have succeeded for lack of a common denominator experts on both sides who understood the issues.

With the funds, consultants for the public advocates came into NU's organization, sat with the company's planners, examined NU's conservation background, and suggested ways of bolstering this base of information with experience and good program design concepts, many from the Pacific Northwest.

Several of the intervenors' consultants had come from the Bonneville Power Administration, which is currently spending around $70 million a year on conservation programs. All told, Bonneville has spent a cumulative total of about $500 million since the early 1980s.

NU further tapped expertise from the Northwest through an ongoing association with Pacific Energy Associates of Portland, Oregon. This small firm, whose principals had also worked at Bonneville, was contracted by NU a year before we began the collaborative process to help us create an energy-efficiency program for commercial and industrial customers. In the residential sector, public interest groups were well represented by officials from Fair Share Development Corporation of Boston.

Sitting across the table from each other, then, were consultants for the intervenors and our own people who had come from the same organization, and that certainly lent itself to reaching a quick understanding. Together, we were able to transfer experience from areas where conservation had been analyzed, developed, evaluated, and successful. If there was anything to hash out among them, it was how to meld consultants' ideas on specific, tested principles about particular customer segments with NU's intimate knowledge of its customers and keen awareness of how to work effectively in a large regulated business environment.

Things Learned in the Process

Both sides came out of the collaborative process with a great deal of new knowledge. Most of the outside parties are very small operations where an understanding of how to implement innovative programs can be coincident with an understanding of the nature of the programs and their goals. These parties learned that in a large corporation like NU (9,000 employees, 1.2 million electric customers over 6,000 square miles), management and field require significant time for understanding both programs and goals, and only then can the field organization turn to the lengthy task of developing detailed implementation plans.

NU learned in particular that higher success rates for conservation programs are achievable only by taking a more segmented approach to marketing. The collaborative process also discovered the opportunity available to use outside residential and business groups to deliver services to customers. Working with community action agencies to deliver services to low-income customers, for example, relieves staffing pressures on the utility work force and provides funding for the community agencies to become involved in the process.

In Connecticut, as in western Massachusetts, the collaborative process involved six basic steps.

- Examine the marketplace by customer segment.
- Identify the key barriers and opportunities for energy savings and load reduction in each group.
- Review existing programs and develop new concepts.
- Prepare new implementation plans for new programs
- Prepare tracking and evaluation plans.
- Introduce the programs to the public.

NU's experience with energy conservation in public housing is an example of how the collaborative process has worked.

NU has known for some time of the potential for achieving energy conservation in public housing. But we knew that public housing projects were extremely difficult to entice into conservation programs because of one very big barrier. The federal Department of Housing and Urban Development's performance funding system dictated that any savings accrued by efficient operation of housing projects had to be turned over to HUD. In short, the more money a housing project saved, the less federal money it got.

NU needed a window of opportunity, which was brought to us through the collaborative process via one of the consultants. It was the Technical Development Corporation of Boston who informed us that HUD had changed its regulations to allow for waivers of the performance funding system, thereby removing public housing's disincentive to invest in energy efficiency.

Seizing upon the first large-scale public housing efficiency opportunity New England, NU prepared a detailed plan in concert with the consultant to structure a program in accordance with HUD guidelines. These HUD guidelines also included a design requirement for program tracking and evaluation — a critical task that will allow for monitoring the program's progress and eventual delivery to public housing projects throughout Connecticut and western Massachusetts. It was only last October that HUD altered its regulations and began allowing for waivers, and the program was announced in February, attesting to the rapidity with which the collaborative process advanced.

Insights into other customer segments led to similar specific program design criteria. In the agricultural sector, a special program was developed for farmers in the two states to capture energy efficiency opportunities that could not be captured by existing commercial or industrial energy audit rebate programs. And for hospitals, NU contributed $1 million to develop the nation's first revolving loan fund for financing energy efficiency improvements in acute-care hospitals.

Throughout the collaborative process, NU gained valuable insights into the views of other parties, as they have into ours. We would also expect this relationship to carry over into other types of long-term resource planning.

The principles of cooperation that were recently developed through this pioneering collaborative proces — agreeing on rules and objectives at the outset, sharing responsibility for the planning process and its outcome, and delegating authority to the staff level — wi be the glue that binds any future work on issues accomplished outside the formal hearing room.

Major Liability Concerns of Utility Companies Noted

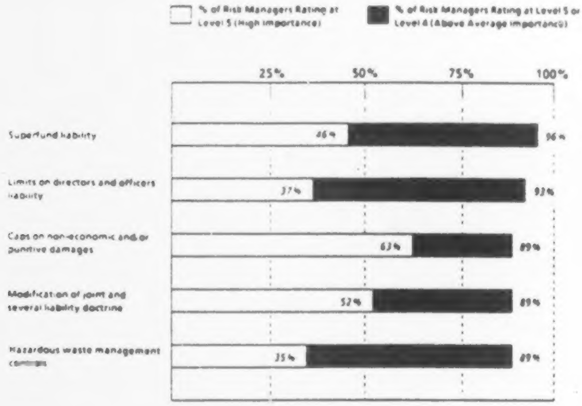
Liability under Superfund, the federal hazardous waste cleanup program, is the most important public policy problem facing utility companies, according to a national survey of corporate insurance buyers.

Ninety-six percent of utility risk managers who responded rated Superfund-related liability as their priority concern in a poll conducted by Alexander & Alexander Services Inc. (A&A). The ranking was the highest given by any industry sector to the 58 issues that were evaluated.

Civil justice reform issues captured three of the top five places. Limits on directors' and officers' liability received a 93 percent rating. This was followed by caps on noneconomic and punitive damages and modification of the "deep pocket" legal doctrine known as joint and several liability. Both topics tied with 89 percent of the utility respondents citing them as important.

Also at 89 percent was concern about hazardous waste management controls.

Five Areas With Highest Level of Importance Rating - Utilities



Robert H. Moore, senior vice president of A&A, has stated: "Our findings reveal that utility company executives are increasingly worried about the costs of environmental impairment liability. In our survey last year, civil justice issues were comparatively more significant."

Utility executives also assigned high priority to health care concerns, employee benefits, and facility safety.

The A&A survey focused on 58 legislative and regulatory risk management topics. More than 300 risk managers from various industries participated. Most represent companies with annual sales of $250 million or more.

The survey was developed by A&A's Government and Industry Affairs office in Washington, D. C., and Radford Associates, part of the Alexander & Alexander Consulting Group Inc., a human resource management subsidiary. A&A Services Inc., is an international insurance brokerage, risk management, and human resource management consulting company.

EXHIBIT

BACK EAST
TO THE FUTURE

Illustration by Jud Guitteau

Northwesterners bring conservation concepts to New England.

by Carlotta Collette

Armond Cohen likes to describe the work he's doing to help New Englanders save electricity as the "fourth generation" of energy conservation programs. Cohen is a senior attorney with the Conservation Law Foundation in Boston, Massachusetts. His organization has systematically intervened in hearings before utility commissions in Connecticut, Maine, Massachusetts and Vermont, each time bringing in expert witnesses from the Pacific Northwest bearing the news that energy conservation should be perceived and purchased as a resource, just like any other source of energy.

Cohen and his new version of the "civilian conservation corps," a cadre of staff and consultants borrowed from the Northwest Power Planning Council, the Bonneville Power Administration, Pacific Power and Light Company, Portland Energy Conservation, Inc., and other agencies, have been successful in every case. Most of New England's major utilities are now a part of the "fourth generation" of conservation efforts.

"The first generation came in the 1970s," Cohen explains, "when conservation meant waiting in gas lines and wearing sweaters. The second generation occurred a little later, when California utilities began giving rebates to customers who saved energy.

The Northwest Power Planning Council pioneered the third generation with big demonstration projects like Energy Edge[1] and the Hood River Conservation Project.[2] Utilities began to see that conservation is a resource that should be purchased like any other resource, not left to consumers to finance. Northwest utilities plowed significant ground by making the first direct investments in conservation resource acquisition programs.

"We're the fourth generation, because we're taking the ideas and demonstrations you've piloted in the Northwest," he says, "and we're running them full scale. We need resources now, and you don't."

Threats of power shortages and consequent blackouts have made headlines in New England since the first years of that region's economic recovery in the mid-1980s. Left with bleak prospects by the 1970s' corporate flight to the "Sunbelt," New England turned itself around and has instead been experiencing steady economic and electrical demand growth since 1983. Average electrical use in the region has been growing faster than 5 percent a year since 1986, despite industry forecasts that predicted something closer to 2 percent average growth rates.

Power constraints are already a reality in the Northeast. New England's Federal Reserve Bank has issued a study of the region's power supplies and with it a warning that current resources could be insufficient to meet needs early in the 1990s. The utility industry's power-needs forecasting entity has reported that "emergency procedures" may be necessary even this summer, if weather patterns mirror last year's heat wave.

New England could cut its future energy requirement by 35 to 57 percent, while maintaining the same level of economic growth and personal comfort, just by making recommended efficiency improvements.

Emergency procedures could include "brownouts," where the utility cuts power output by about 5 percent, and "rolling blackouts," where power is turned off in one place and then another so that no systemwide shutdown occurs.

Simply stated, New England's economic recovery proved to be a mixed blessing. The region's need for power, particularly at peak-use times, grew faster than its utilities could build new power plants and adequate transmission and distribution systems. Furthermore, two completed nuclear power plants (the region gets 28 percent of its power from nuclear) have had spotty records getting up to speed over public protests and technical problems.

At least one major utility, New England Electric System (NEES), which serves about 1.2 million customers in Massachusetts, Rhode Island and New Hampshire, announced in 1985 that it intended to pull its growth rate back to only about 1.2 percent a year.

New England Electric had led the region in 1979, by releasing its "NEESPLAN," which called for investments in conservation and measures to shift energy consumption from peak-use periods to other times of day. (Utilities must build enough power plants or other resources to cover the times when most customers are likely to be drawing on the system's supplies of power. By shifting some of this peak use, so called "load management" strategies reduce the total amount of electricity the utility must be prepared to deliver at any one time.)

But even with its energy plan, New England Electric and other Northeast utilities engaged in only small, pilot and demonstration conservation programs on the assumption that growth would slow and the power wouldn't be needed.

In 1987, the pace of change picked up. The Conservation Law Foundation and more than two dozen public interest and consumer groups formed the New England Energy Policy Council. Their first product was a plan for New England's energy future called *Power to Spare*.

Power to Spare pointed out that New England spends over $7 billion each year for electricity, at rates that are 25 percent higher than the national average. Some of that big bill was payment for power plants constructed a decade earlier, contributing substantially to a doubling of regional electric rates between 1974 and 1985. The threat that the region might be about to go that same route and build additional electricity generating resources led the council to illustrate the cost advantages of efficiency over new generation.

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[1] Energy Edge is a design assistance program sponsored by the Bonneville Power Administration to help owners and builders of commercial structures attain high levels of energy efficiency.

[2] The Hood River Conservation Project was designed to test the participation rate for a conservation program where all the costs were paid for by the utility. More than 90 percent of the electrically heated homes in Hood River County, Oregon, were insulated through the program.

By the New England council's calculations, that region could cut its future energy requirement by 35 to 57 percent, while maintaining the same level of economic growth and personal comfort, just by making recommended efficiency improvements. If only half the council's suggestions were taken, the region would require about 17 percent less electricity than utilities were predicting. Furthermore, the study found that it would cost New England's utilities between one-quarter and half as much to "buy" conservation outright as it would to get the same amount of power from new conventional power plants.

But *Power to Spare* also cited three major obstacles to full implementation of conservation programs in New England: lack of information about new energy saving technologies; lack of resources or incentives to purchase conservation equipment or pay for efficiency improvements; and lack of utility action to acquire conserved electricity as a resource.

To tackle these, the Energy Policy Council proposed an action plan for New England. Actions focused on utility-sponsored programs to design and fund cost-effective efficiency improvements and load management measures in both residences and businesses. Despite the apparent logic and practicality of such an agenda, it took a rapid sequence of events to move the utilities.

In August 1987, the first voltage reduction brownouts in New England in more than a decade signaled problems meeting electricity demands with existing supplies. Then between September and December, armed with *Power to Spare* and backed by a team of energy experts from around the country (primarily the Pacific Northwest), the Conservation Law Foundation intervened in the first of what would become a string of rate and resource acquisition cases.

"*Power to Spare* was a conceptual 'shot across the bow'," says Cohen. "But, unlike the Pacific Northwest, we had nothing like the [Northwest Power] Act to enforce conservation investments. We needed a legal forum to gain support."

The Eastern utilities are now launching some of the biggest direct investment energy-efficiency projects ever attempted.

Connecticut

The first forum came in October 1987 in Connecticut. Connecticut Light and Power Company, New England's largest retail utility, had requested a rate increase and a complementary *decrease* in its spending on conservation. The Connecticut Department of Public Utility Control, the state's regulatory commission, was hearing the rate case.

The Conservation Law Foundation brought in Dr. Arthur Rosenfeld, head of building energy-efficiency research at Lawrence Berkeley Laboratory in California; Tom Foley, manager of resource planning for the Northwest Power Planning Council, and Dr. H. Gil Peach, who was then a conservation manager with Pacific Power and Light Company in Portland, Oregon.

Connecticut Light and Power was basing its proposed conservation cutback on the fact that it already had surplus energy capacity, and that conservation could be a natural outcome of market pressures.

"What swung the commission was Tom Foley arguing that even in a surplus there's a lot you can do," Cohen relates. Foley explained that some conservation investments had to be made when buildings are under construction to gain the best value and the most savings. He also described the Northwest's experience with building the capability to gear up programs when the power is needed. The further asset of using low-cost conservation as a means of stabilizing energy loads was also pointed out by Foley.

"Then Gil Peach told the commission about Pacific Power and Light's experience with the Hood River Conservation Project," Cohen continues. "How that utility was paying for a 'conservation power plant.'" The commission was convinced. It ordered the Connecticut utility to nearly *double* its spending on conservation, and further ordered cooperation between the utility and its adversaries, the Conservation Law Foundation.

Northeast Utilities, the parent company of Connecticut Light and Power, put up an initial $200,000 to cover expenses for the expert witnesses whose testimony had won the case for the Conservation Law Foundation and to keep the witnesses working with utility staff to design energy saving programs for the utility's customer groups. The Law Foundation was kept separate from the financial arrangement so that it could fairly evaluate the utility's compliance with the commission's ruling.

By early summer 1988, the Connecticut utility had in place the mechanisms to operate some of the most ambitious conservation programs in the nation.

Massachusetts

Massachusetts entered the picture in the spring of 1988. The Conservation Law Foundation brought its efficiency experts, including additional Northwesterners, to testify before the Massachusetts Department of Public Utilities. This time, the group spent two days detailing the potential energy savings from conservation programs, describing ways to manage direct investments in efficiency and protect utilities' profit margins, and critiquing existing Massachusetts conservation efforts.

While the department was still considering the arguments for conservation, all seven Massachusetts investor-owned utilities came forward on their own to negotiate cooperative agreements with the Law Foundation. The uncommon collaboration of conservation experts from the West and Eastern utilities was growing. Bringing Massachusetts in also carried bits of Rhode Island and New Hampshire's energy loads, because the New England Electric System, one of the Massachusetts signers, sells 30 percent of its electricity through subsidiary power companies in those states.

Vermont

By this time, July 1988, Cohen and the road show of energy experts were developing major conservation proposals in Connecticut, Massachusetts, Rhode Island and New Hampshire. Only Vermont and Maine still needed convincing.

Vermont had been on the original campaign trail when *Power to Spare* was first released. The New England Energy Policy Council had made a presentation of the study's findings to Vermont's legislative energy committee. The state's Public Service Board followed up by ordering an investigation into the benefits and costs of utility investments in conservation.

In July, the conservation team made an appearance before the board, and stood for cross examination by utility representatives. In this case, the Vermont board questioned its own authority to order the sort of cooperation that was taking place elsewhere in the region, but Vermont's largest utility, Central Vermont Public Service Company, decided to work with the conservationists.

On July 13, 1989, the Public Service Board announced that it was ordering all of the state's utilities to develop least-cost power plans and to invest in all cost-effective conservation available. The board

referred repeatedly to the Northwest's experience. It even carried over the 10-percent cost advantage conservation is given over generating resources when determining which resources utilities should invest in first. Another 5 percent was added to account for "otherwise unrecognized external costs" of generating resources.

Maine

The Conservation Law Foundation had been discussing the virtues of conservation with Central Maine Power, the state's largest utility, since September 1987. The Foundation had intervened in a proceeding before the Maine Public Utility Commission when the power company had proposed buying 900 megawatts of energy and capacity from Canada.

No settlement was reached in 1987, so the conservation group brought in its team of experts. It took some time, but in January 1989, the utility commission ruled in favor of the conservation option, turning down Maine's request for power imports until the utility had quantified the savings it could garner from efficiency and load management programs.

Today, nearly all of New England's utilities are bragging about their conservation programs. In full page advertisements, Massachusetts Electric, Central Vermont Public Service Corporation and others declare their "commitment to conservation" as a "win:win opportunity."

Bill Ellis, chief executive officer at Northeast Utilities, has described his company's experience in an article published in *Public Utilities Fortnightly*. "Key among the benefits of the collaborative process," he wrote, "was the potential to reduce dramatically the burdensome amount of conservation and load management litigation in future rate cases and to limit the focus to essential issues. This process alone," he added, "would save the utility significant sums in paperwork, cross-examination, and time ..."

Together, the Eastern utilities are now launching some of the biggest direct investment energy-efficiency projects ever attempted. Projected savings over the next decade amount to nearly 20 percent of the region's expected power needs during that period — and this would be before the programs are fully implemented.

Lydia Pastuzek, director of demand planning at New England Electric System, figures the new conservation programs and expansion of some existing ones at the utility could cut their need for new resources by one-third. "Our immediate goal is to reduce our peak load by 300 megawatts by 1991. We've already achieved 150 megawatts."

"Negative electricity demand growth is not an unreasonable target, even in an economically robust area such as New England," suggests a report prepared by the law group.

Cohen freely acknowledges the debt his group owes the Northwesterners who paved the way for New England's turnaround. In fact, Cohen borrowed Tom Foley from the Northwest Power Planning Council for six months to help New England's utility managers determine ways to incorporate conservation along with more conventional resources in utility planning. Cohen's organization and the utilities he is now collaborating with are paying all of Foley's expenses as well as reimbursing the Council for the cost of hiring support in Foley's absence.

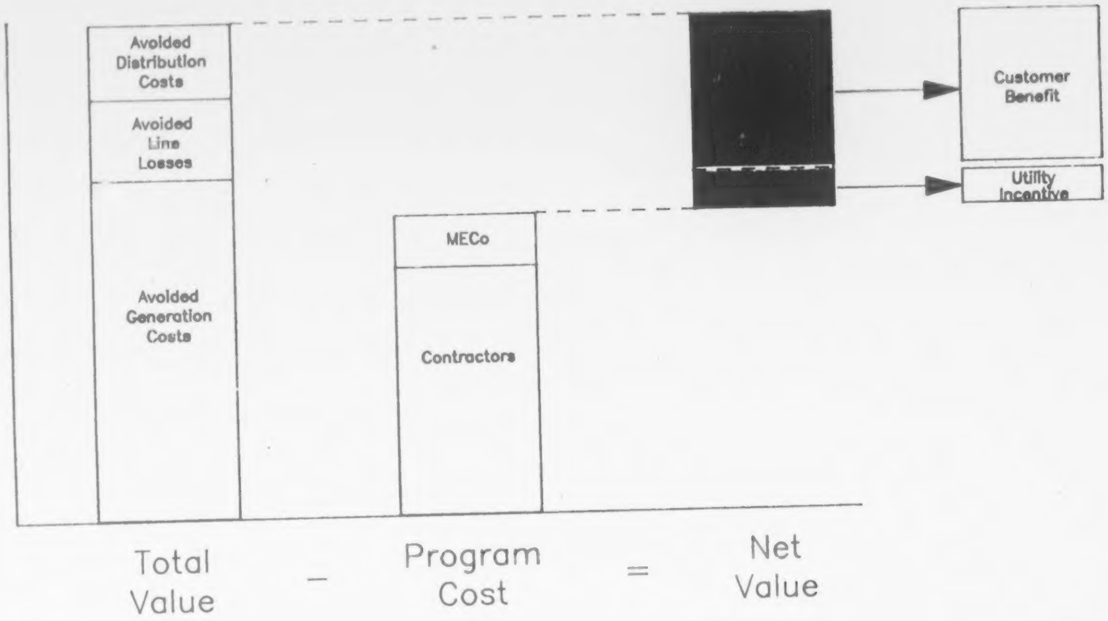
For the Council's part, Foley's half-year assignment in the Northeast will provide experience with fully implementing and evaluating conservation programs. "We want to monitor the heck out of these programs so there will be impeccable data," explains Cohen. "When you need the power in the Northwest, we'll share with you our experience of what worked and what didn't."

Conservation's fourth generation is widening and deepening the trail to tomorrow's efficiency. It shouldn't be too long before that expanded path returns to the Northwest. ■

Cost Recovery

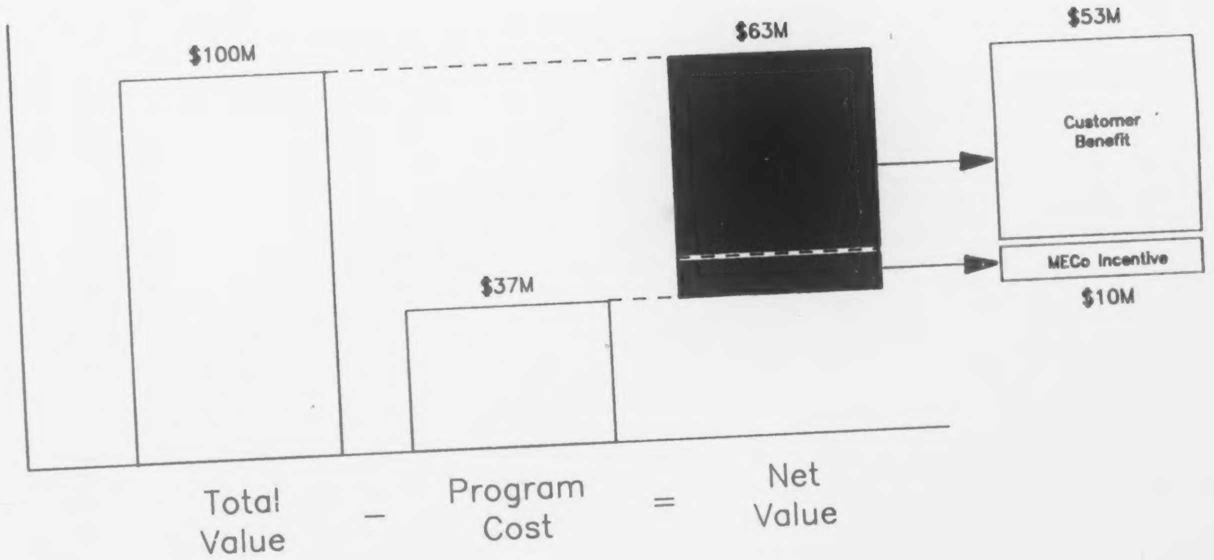
- Pre-approved contract for 1 year
- MECo guarantees cost will not exceed value; departure from historical ratemaking approach consistent with innovative DPU order
- Price includes mechanisms to encourage MECo to maximize the penetration of C&LM programs and to encourage these programs be conducted as efficiently as possible

The Incentive Structure is based on the difference between the value of the conservation and the cost of the conservation.


Avoided Distribution Costs
Avoided Line Losses
Avoided Generation Costs
MECo
Contractors
Customer Benefit
Utility Incentive
Total Value
–
Program Cost
=
Net Value

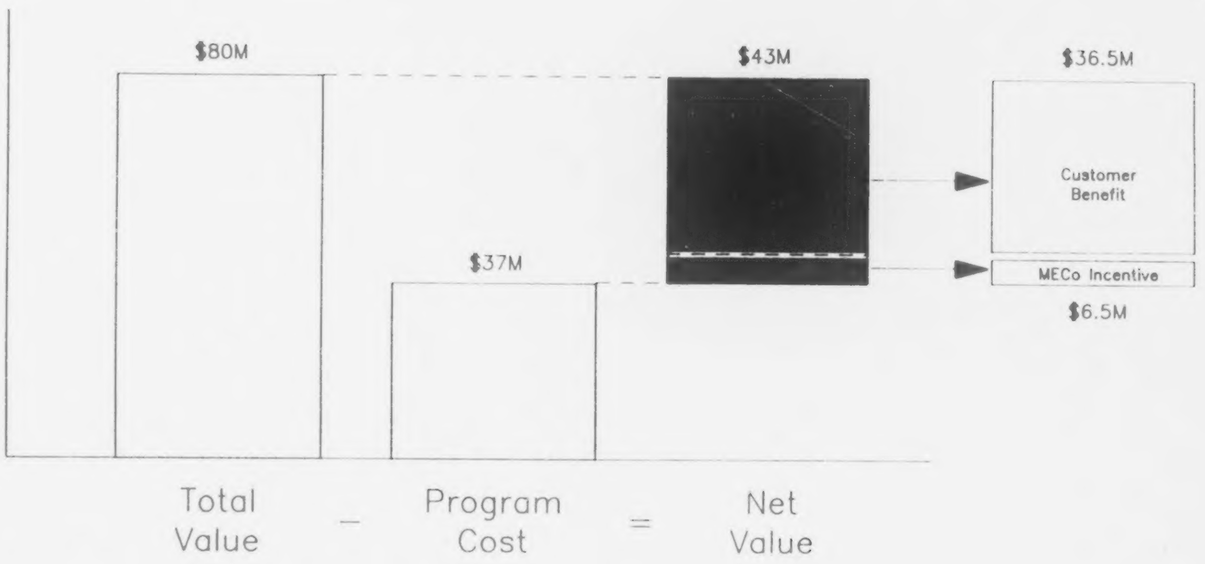
The incentive allocates over 80% of Net Value to customers.

If program goals are met, customer benefits will be substantial.



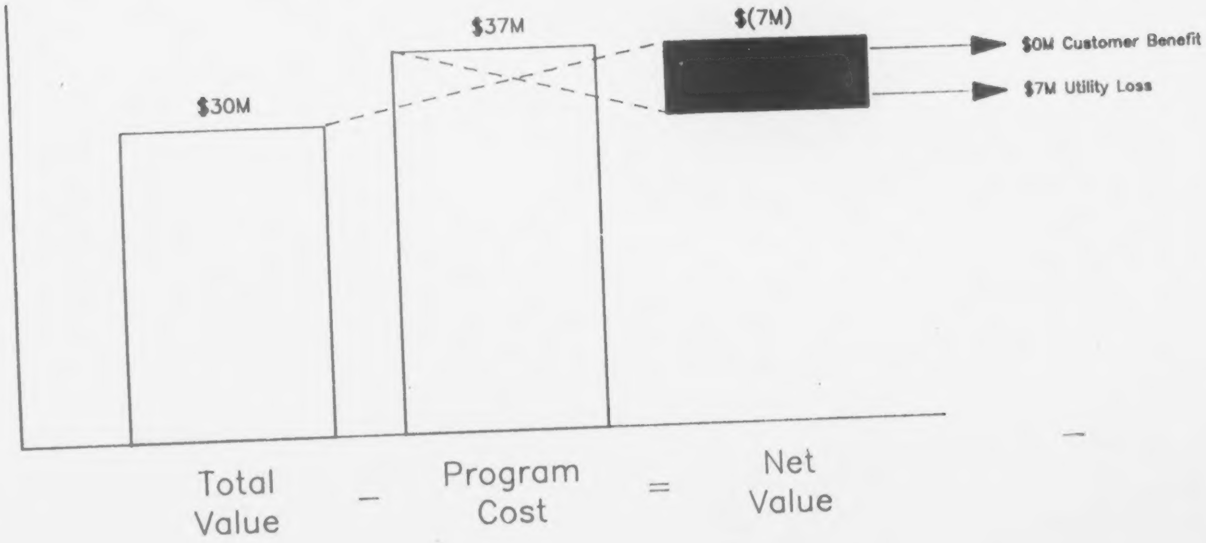
Total Value = $100M
Total Customer Cost = $47M
Net Customer Benefit = $53M

If less value is produced, the utility incentive payment is smaller.



Total Value = $80.0M
Total Customer Cost = $43.5M
Net Customer Benefit = $36.5M

If program costs exceed value, Cost Recovery is capped at value.



Total Value = $30M
Total Customer Cost = $30M
Net Customer Benefit = $0M

Senator **Wirth**. Thank you very much, Mr. Cohen. Our final witness today is Joshua Bar-Lev, Vice President and General Counsel for Luz International in Los Angeles. We appreciated your hospitality when we visited Luz last winter and look forward to hearing from you. Thank you very much.

STATEMENT OF JOSHUA BAR-LEV, VICE PRESIDENT AND GENERAL COUNSEL, LUZ INTERNATIONAL LIMITED

Mr. **Bar-Lev**. My name is Joshua Bar-Lev and I am Vice President and General Counsel of Luz International Limited. Luz designs, builds and operates environmentally benign solar electric power plants.

In the past five years, we have built and now operate 194 megawatts of installed capacity. We are now building our first 80 megawatt plant which is scheduled to be placed in service by the end of this year.

As the Committee reviews proposed PURPA amendments in the context of global warming legislation, we are pleased that you are considering including provisions to encourage the commercialization of solar electric power generation by removing the size limitations.

In fact, if I would summarize my testimony in a few words I would say that solar energy is here. It is clean, and it is almost cost-competitive, and with your help it will be cost-competitive.

In the past, Congress has given our industry a tremendous boost to become commercially viable. Today, if solar technology is permitted to compete without the constraint of a size limitation, utility-scale solar facilities will be able to participate in the highly competitive electric power generation market with the benefit to the American citizen of significant reductions in emissions of nitrous oxides, nitrogen oxides and global warming gases and a significant reduction in oil imports. In fact, our 80-megawatt plant is going to displace 450,000 barrels of oil a year.

To date, Luz has placed in service the world's seventh largest solar plant, six 30-megawatt facilities and one 14-megawatt facility, all in the Mojave Desert in California. The output of these facilities is enough to meet the residential needs of more than 270,000 people in Southern California. Our eighth facility, the 80-megawatt facility, is the first of its kind. These facilities have been built on time, on budget, and have performed beyond warranted levels of output and reliability.

When construction of our current inventory of contracts is completed, 654 megawatts of solar electric power will produce enough electricity to meet the residential needs of over 900,000—more people than live in cities the size of San Francisco, San Antonio, Denver or Washington, D.C. We will be 4 percent of Southern California Edison's peak capacity.

Emissions from Luz's facilities are far below the level of natural gas facilities, the cleanest fossil fuel alternative. Our first seven plants displace the equivalent of about 800 million pounds of CO_2 per year compared to a coal plant and 420 million pounds of CO_2 compared to a natural gas plant. Our eighth plant will abate 400 million pounds of CO_2 per year compared to a coal plant and 300 million pounds compared to an oil-fired plant.

Luz has combined simple principles with state-of-the-art engineering and electronics to successfully demonstrate that renewable and nonpolluting solar power can meet utility standards of cost efficiency and reliability.

It surprises people to know that we developed these modular solar plants in less than 18 months from permitting to completion. In fact, the construction period for the 80-megawatt facility that we are building right now is eight months from ground-breaking April 1st to placement in service before the end of this year.

Another significant benefit of our solar technology is its peak-load power plants, which almost perfectly track the load requirements of the purchasing utility. Since peak demand periods in Southern California fall mostly during summer daylight periods, Luz facilities are able to operate during almost 100 percent of the on-peak hours, and in contrast the facilities shut down during the middle of the night when power is not needed.

Luz has invested heavily in research and development to reduce its cost by constantly improving solar technology and construction methods and we have reduced generating costs from approximately 25 cents per kilowatt-hour in 1984 at the first 14-megawatt facility to 12 cents at our 30-megawatt facility to a projected 8 cents at the 80-megawatt facility now being completed. That is a 67 percent reduction in cost in just five years, within earshot of conventional power costs even if you do not add the cost of pollution to the cost of those other technologies.

However, it is clear that 8 cents is still not enough for solar facilities to remain competitive. Our current target is to reduce the cost of generation from 8 to 6 cents per kilowatt-hour, a goal we think is achievable if solar facilities can be built at larger sizes. The results of the 1987 legislation prove that economies of scale combined with aggressive R&D will make this technology competitive with conventional technologies and the American citizen will be the real beneficiary of this legislation.

In 1978, when PURPA was enacted, solar electric generating facilities of 30 megawatts were only a dream. By 1987, you recognized a compelling need to allow an increase in the size of solar facilities to 80 megawatts.

At a time of increasing concern over the impact of emissions of nitrous oxides and global warming gases, no public purpose—no public purpose at all—would be served by holding back the further development of solar technology. We ask you now to let the solar industry find the ideal economic size for its technology and allow solar facilities to compete on a level playing field with cogeneration.

Thank you very much. I would be happy to answer any questions you have.

[The prepared statement of Mr. Bar-Lev follows:]

Testimony of Joshua Bar-Lev
Vice-President and General Counsel
Hearings on S.324
Committee on Energy and Natural Resources
United States Senate
November 7, 1989

Mr. Chairman and Members of the Committee, my name is Joshua Bar-Lev and I am Vice President and General Counsel of Luz International Limited. Luz designs, builds and operates utility scale solar electric power plants. At the present time we operate 194 megawatts of installed capacity with an additional 80 megawatts under construction and scheduled to be placed in service by the end of 1989.

I appreciate the opportunity to testify in support of proposed legislation to encourage the commercialization of solar electric power generation by removing artificial scale limitations. This legislation will significantly enhance the opportunities for utility scale solar facilities to participate in the highly competitive electric power generation market.

By enabling solar electric generating facilities to compete without the constraint of an uneconomic size limitation, this legislation will help reduce emissions of nitrous oxides and global warming gases at no cost to either taxpayers or utility ratepayers.

Background and Current Status of LUZ Technology

To date, Luz has placed in service the world's seven largest solar plants--six 30-megawatt facilities and one 14-megawatt facility--all in the Mojave Desert in California. The output of these facilities, which is enough to meet the residential needs of more than 270,000 people in Southern California, is sold to Southern California Edison. Our eighth facility, now in the final stages of construction, is a first-of-a-kind 80 megawatt solar power plant. These facilities have performed beyond warranted levels of output and reliability and have earned high marks from Southern California Edison for their contribution to the utility's peak load resource base.

Unlike photovoltaics, with which you may be more familiar, Luz's technology uses parabolic trough reflector assemblies to focus the heat of the sun and increase the temperature of a heat transfer fluid. This fluid circulates through vacuum insulated pipes, in turn, producing steam through a conventional heat exchanger and electricity through a conventional steam turbine generator.

Luz has combined simple principles with state-of-the-art engineering and electronics to successfully demonstrate that renewable and non-polluting solar power can meet utility standards of cost, efficiency and reliability. The short lead time required for development of these modular solar plants -- less than 18 months from permitting to completion -- also provides flexibility to accommodate changing utility demand projections. In fact, the construction period for our first 80 megawatt plant will be only eight months from groundbreaking to placement in service.

Our facilities are peak load power plants which closely track the load requirements of our purchasing utility. Since peak demand periods in Southern California fall mostly during summer daylight periods, Luz facilities are able to operate during almost 100 percent of the on-peak hours; 80 percent of the summer mid-peak hours and 60 percent of the winter mid-peak hours. In contrast we operate during only 13 percent of all off-peak hours.

To assure reliability even during cloudy periods and to provide power during high demand evening periods, Luz facilities are designed to operate, within the strict limits allowed under PURPA, using natural gas, the cleanest fossil fuel, as a supplementary source of energy.

When construction of our current inventory of contracts is completed, 654 megawatts of solar electric power will produce enough electricity to meet the residential needs of over 900,000 people--more people than live in cities the size of San Francisco, San Antonio, Denver or Washington, D.C.

Financing Solar Electric Power Plants

All of our facilities have been developed as qualifying facilities under PURPA, financed entirely with private capital.

In order to maintain an adequate return to attract equity to these projects, Luz has invested heavily in research and development to reduce costs and remain competitive. By constantly improving both the technology and construction methods, the cost of generating solar electric power has dropped from approximately 25 cents per kilowatt hour at our first 14 megawatt facility to 12 cents at our 30 megawatt facilities, to a projected 8 cents at the 80 megawatt facility now being completed.

Legislation enacted in 1987, allowing solar facilities to increase from 30 to 80 megawatts, was critical to the survival of our technology. Under current market conditions a 30 megawatt solar thermal power plant would simply not be economically viable. Economies of scale associated with the construction, operation and maintenance of the larger power block are a key component of the savings that enabled us to reduce the cost of generation from 12 to 8 cents per kilowatt hour. The increase in size from from 30 to 80 megawatts is directly responsible for a 20 percent reduction in costs.

Current Outlook

As we evaluate the outlook for the electric power generation market, it is clear that further cost reductions will be necessary for solar facilities to remain competitive. Our current target is to reduce the cost of generation from 8 to 6 cents per kilowatt hour, a goal which we think is achievable if solar facilities can be built at larger sizes. Removing the size limit on solar facilities would enable us to realize further savings of approximately 20 percent.

Since the marketplace for peak load generation in the southwest is dominated by natural gas fired technologies, Luz has no choice but to compete in price with natural gas generation. Under the best of circumstances this is difficult because a solar facility has much larger capital requirements -- a result of substituting construction of a solar field for long term fuel purchases. Since the value of the solar field is based not on our cost of construction but on current and projected gas prices, the challenge has become even more difficult with gas prices remaining soft for a sustained period of time.

Need for Proposed Legislation

For the foreseeable future we believe that it will be necessary for solar thermal facilities to be built as qualifying facilities under PURPA. The rapid evolution of our technology has made it possible for us to remain marginal but viable in a market where external factors, including interest rates as well as fossil fuel prices, have been problematic. We believe that solar thermal technology is on the verge of becoming truly commercial, and expect that in the future, utilities will seriously consider purchasing not just the output of our facilities but the equipment itself.

However, as we plan for the future, we see a need for an intermediate stage of development before utilities are likely to purchase our equipment. For several reasons, we believe that allowing larger solar facilities to be built under PURPA will accelerate the acceptance of this technology as an option for utilities planning resource additions.

In general, utilities prefer to purchase power plants in units larger than 80 megawatts. Moreover, no utility will want to be the first to build a solar power plant larger than facilities which are already operating. With the additional economies of scale resulting from larger facilities, we hope to demonstrate over a sustained period of time that solar thermal generation can be truly commercial, in size configurations most attractive to utility planners.

Benefits of Proposed Legislation

The proposed legislation would encourage the development of clean and renewable solar energy at no cost to either the ratepayer or the taxpayer.

There are many misconceptions about the rates paid for power under PURPA, particularly in California. At the present time, rates paid for power purchased under PURPA truly reflect competitive market activity. Although the early implementation of PURPA in California resulted in Standard Offer 4 contracts with rates based on projected energy price increases that proved to be higher than actual energy prices, these contracts are no longer available. Existing Standard Offer 2 contracts include pricing based on quarterly adjusted gas prices and any new contracts will be based on competitively bid pricing under a new bidding program being implemented in California as in many other states.

Since the price paid for power is not based on our cost of generation, our ability to remain in the marketplace is limited to our ability to bring our costs down to a competitive level. The rates paid for solar power will be no higher than the rates paid for gas-fired cogeneration or any other source.

As with all contracts under PURPA, responsibility for assuring that rates are fair both to the generators and the ratepayers falls to the state public utility commissions. Our experience in California suggests that with experience, state commissions have become acutely aware of the need to balance many factors in arriving at judgments in this area and those judgments will determine pricing levels that generally prevail, regardless of what size solar facilities may be developed under PURPA.

The real benefit of allowing larger solar facilities to acheieve economies of scale under under PURPA is that at no additional cost to the ratepayer a clean and renewable energy source will be able to flourish. Emissions from Luz facilities are far below the level of natural gas facilities -- the cleanest fossil fuel alternative. Our carbon dioxide emissions are .27 pounds per kilowatt hour compared to 1.1 pounds for a natural gas facility; our emissions of nitrous oxides are 6 parts per million for each kilowatt hour compared to 125 parts per million for a conventional gas fired plant.

Fossil fuel fired cogeneration facilities are not limited in size under PURPA. Although cogeneration makes a significant contribution to improving the efficiency of energy use, we believe it is only fair and in the public interest to allow solar facilities to compete under PURPA on a level playing field with these larger facilities. If both were able to benefit equally from economies of scale, the benefits to the public would be more efficient and cleaner electric power generation, and there would be no costs.

Conclusion

Congress has shown its support for solar technology by responding in a timely manner to the evolving needs and potentials of the industry. This response has enabled solar technology to prove itself reliable and capable of being well integrated into a utility system.

In 1978, when PURPA was enacted, solar electric generating facilities of 30 megawatts were only a dream. By 1987 the need to increase in size to 80 megawatts was compelling and Congress responded by allowing the increase in size from 30 to 80 megawatts. At the present time, to further encourage the development of clean renewable solar technology, at a time of increasing concern over the impact of emissions of nitrous oxides and global warming gases, no public purpose would be served by holding back the further development of solar technology with a size limit that no longer reflects that ideal economic configuration of solar electric generating facilities.

We are grateful for the interest that Congress and Members of this Committee have shown in the past and we appreciate the invitation to appear here this morning to present our views.

Thank you very much, I would be delighted to answer any questions you may have.

Senator WIRTH. Mr. Bar-Lev, thank you very much, and I want to come back to a question for you. Let me start, if I might, with sort of the broad-sweep question. It seems to me that the issue in front of us relates to the removal of disincentives for utilities to pursue conservation.

If we were to do that as in the legislation, would that be enough, or do we have to go beyond that to create the mandatory purchase program? Is removing those disincentives enough, or do we have to put a second layer on there?

Ms. PASTUSZEK. If I may comment, removing the disincentives is only the first step. The second step, though, is not necessarily the one that is posed in your question.

I think there should also be an incentive for utilities who make investments in least-cost or conservation-type activities. There have been efforts, such as the California ERAM, or lost revenue adjustments, which make the utility whole, but they do not really reward the utility or allow the utility to make a profit on conservation and load management investments.

We have filed with our three state regulatory commissions a proposal that would allow us to share some of the savings and benefits that are created by our conservation programs and we think that this should provide the appropriate signal not only for New England Electric, but for other utilities to move in this direction.

Senator WIRTH. When we write in the legislation to remove disincentives, it would be my interpretation that would assume that utilities can make the same amount of profit on conservation as it does on the supply side. Is that not clear in the legislation? I mean, you make the distinction that we should be able to have that kind of a profit margin for conservation as well. Isn't that explicit in the legislation?

Ms. PASTUSZEK. I do not think that that is explicit in the legislation, because there is a lot of debate on this particular issue at the current time.

There are people who think that compensating the utilities for lost revenues will remove the disincentive, or that rate-basing will provide an incentive, and we do not agree with those conclusions. I think that if that is the intent of the bill, it could be worded more clearly to enunciate that.

Senator WIRTH. Mr. Cohen?

Mr. COHEN. Senator Wirth, I would like to comment that I think that there are three obstacles to moving efficiently in a big way in the utility sector. The first is the one that is attacked in the bill, and that is the existing disincentives for revenue loss. But there are two more that I think deserve attention.

The second, I would say, is the corporate culture of American utilities, and by and large you find a heavy psychological, institutional supply side orientation, notwithstanding the attempts that have been made to get those companies moving, both regulatory incentives and planning mandates.

Senator WIRTH. Should we put a line item in the bill requiring a change? [Laughter.]

Mr. COHEN. No. What I am really suggesting, Senator, is that the Federal Government needs to show more active leadership in specifying the kinds of activities that they want to see the utilities move forward on.

My concern about simply requiring utilities to buy, passively, energy efficiency from third-party providers, is that many of the recalcitrant utilities may simply say well, that is great. We do not have to do anything. We just have to wait for the bids to come in.

From my understanding of the research on the energy service market in New England, the kinds of bids that are going to come in are not necessarily going to cover the kind of broad range of end uses that you want to see covered, nor are they going to necessarily dig out the deepest savings.

Senator WIRTH. Two questions related to that, then. Is the impression incorrect that the culture in fact is changing? I would think that the culture has changed very dramatically, say from the time before PURPA was passed. You know, the world has changed very significantly, one, and you do not think it is changing rapidly enough, I gather.

Second, related to your final point, should that not, or could that not, be left to state regulatory commissions to build in the kind of requirements or incentives so the utilities would "dig out"—your words—"dig out" aggressive and workable conservation programs?

Mr. COHEN. I think your first observation is correct. It is changing. Is it changing fast enough? I do not think so, particularly when we are talking about the scale of the threat of climatic change and the rapidity with which those problems might appear.

It has been ten years or more since PURPA was passed, and it has been a very slow evolution and I would suggest that where the corporate culture is changing, it is changing because of very aggressive regulatory leadership at the state level and in regulatory fora.

Senator WIRTH. We have only had George Bush for a year. [Laughter.]

Mr. COHEN. Well, we can hope for the best but maybe we should count on activity at another level. The point about leaving it to the states, though, is of great concern to me as well.

The fact of the matter is, other than a handful of states we do not see real clear leadership at this point. You have very vague mandates for least-cost planning, and so forth, and very little by way of on-the-ground action, and that is the contrast I am trying to draw with New England.

I think that one thing the Federal Government does well is picking up on good state-level experiments, local experiments. Sharing information, replicating them throughout the Nation, and I think you have got a public policy experiment in New England that shows signs of working.

Senator WIRTH. How do we best do that, Mr. Cohen? Do we do that through mandates, or do you do that through developing the capability at DOE to spread that, or how do you do that?

Mr. COHEN. I think it is both. I think the information-sharing component is very important. I would mention that one of the key drivers in developing the New England program was the Lawrence Berkeley Laboratory, which as you know receives funding from the Department of Energy. That kind of information-spreading activity is essential.

But the specific proposal I make in my testimony is that this Committee can learn somewhat from the New England experience and say, as a general matter, utilities should be pursuing programs to bring up the efficiency of new buildings coming on line above existing code requirements where it is cost-effective to do so and retrofitting existing buildings, providing technical assistance to make industrial operations more efficient.

You do not have to micro-manage, but I think you have to provide a little bit more definite leadership than simply to say least-cost planning, because that means a million things to a million people.

Senator WIRTH. Thank you, Mr. Cohen. Mr. Wolf, let me ask you also in the process of this, could you give us an explanation of what you mean by the all-resources test?

Mr. WOLF. Sure, but first let me address your question, because I think you have hit the fundamental issue and it has already been said that the culture is changing, but I think very, very slowly, and if I could differentiate the two provisions in the bill that you have asked about, the first one about removing disincentives, what has been called leveling the playing field I think will accomplish a lot, but the question is, over what time frame?

I use the analogy, rather than football, of baseball, saying right now we do not have a symmetrical ballpark and most utility executives that get up to bat, they are all going for that supply side fence. They see that is very—closer in, and that is where they are going to keep hitting, even after you change the ballpark and make it symmetrical.

You are not going to change the batters that come up to bat, and I think what your second provision does is it starts getting some other batters into the lineup, and by qualifying conservation you are putting in people more attuned to reaching that other fence.

Over the long-term I think just leveling the playing field or making the symmetrical ballpark will have a significant effect. In the short-term, though, I do not think it will be significant and I think the qualifying conservation provision is quite complementary and will have a very good effect to it.

Senator WIRTH. The utilities respond by saying you are Jose Canseco, and you have got a gun in your car and you are putting it to our heads unnecessarily to carry your analogy all the way out.

Mr. WOLF. To carry it all the way out, the utility executives we have spoken to—again, when you are out in the field as Armond said and you hit the trenches, they will tell you off the record what is basically going on in their own utility and they understand what the PR angle is on efficiency and what the CEO message may be. But they say when do we get the bottom line resources to do what we need to do.

By and large the answer is no, we do not, and these are the reasons why we do not. And they also frankly do talk about attitude, the people coming up through the system. They are different. Very few of those are really at the top management level where they can make the allocation and resource decisions in the utility.

To answer your second question, just about the all resources test which we would endorse as well and deleting the no losers test from the testimony. That focuses not just on the rate that is being charged for the electricity or the marginal cost of generation . You look at the actual cost of the investment. If it is insulation in the customer's facility, you do not say well, if they are charging them five cents, the marginal generation is seven cents.

You say what we are concerned about from the societal perspective is how much does the insulation cost. Does it cost $10 a batt, $30 a batt or $50 a batt and you compare that as the real resource cost with what is the real resource cost of generation, and we think that might be a better approach as was endorsed by Mr. Harding.

Senator **WIRTH**. Now, how do you get a handle on what those costs really are? Say, Wolf Enterprises are in the conservation business and you are going to insulate people's houses and Wolf Enterprises knows that the cost of Wolf Enterprises are going to be built into the rate base. They have got to pay for it, right? So, you can do anything you want to do, and you get into what somebody mentioned earlier where you are gold plating operations. How do you avoid that?

Mr. **WOLF**. That is right. You do want to avoid gold plating conservation expenditures, and you look at is there is marketplace now in insulation separate from utility purchasers of it. What is the variable speed driver for motor costs if an industrial customer wants to go install one. What is the cost of that motor? What is the cost of the new efficient lighting systems.

You look at what the market is in those products. Just as there are, in fact, distortions of the market on the energy supply side where not many people aside from utility companies are putting up generating plants, but you try to do the best handle you can on what are the actual resources of both the conservation or the efficiency improvement and on the supply side and then compare those.

The so-called no losers test is a proxy. Some people have advocated it as a way of doing that, but we think that might lead to unnecessary distortions in the market.

Senator **WIRTH**. Okay, let me just finish this off. You're suggesting that what you do on the qualifying conservation provision, you don't require that of states that have all source bidding, is that right?

Mr. **WOLF**. That includes demand side bidding, that is correct. Some states have only gone to supply side bidding.

Senator **WIRTH**. If we require states to go through the process of ensuring that least cost plans are the most profitable plans, would that obviate the need for qualifying conservation?

Mr. **WOLF**. No, because, again, I think there is a differentiation between the planning and the doing and the investing, and as I said before, least cost planning does not necessarily mean least cost implementing, and I think you will get by qualifying conservation those companies like Mr. Harding's companies and others coming out of the market and saying we can do things for you, and we want to make sure they get the opportunity to be asked.

Mr. **PASTUSZEK**. If I could comment on that, I think that to extend the baseball analogy, a very effective way to get companies to do least cost doing would be to move the demand side fence closer just like you proposed that the supply side fence is closer, and the way that we have proposed that be done and it also avoids the gold plating issue is that the company be given a percentage of the gross value that it creates by saving kilowatts and kilowatt hours as well as a percentage of the savings that it creates and more of a shared savings format.

This gives the company the incentive both to maximize the demand side reductions and to do them at the lowest possible cost because they get a share of the savings that are created.

Again, I think it is sort of a philosophical issue of do you want to use the carrot or with the stick, and I think that if you make conservation and load management a profitable undertaking for utilities, you will see them moving that direction. After all, the investments in power plants are not exactly ones that utilities are anxious to make these days.

So, let us find a way for those dollars to be invested effectively and meet society's goals at the same time.

Senator WIRTH. Mr. Harding.

Mr. HARDING. Well, I wanted to also try to extend Mr. Wolf's baseball analogy which is probably getting threadbare by now, simply to say that I agree very strongly that adding some new batters complements the moving of the fences, and I think that what tends to happen—and I have worked both as a utility program manager as well as in third parties—that when utility staffs see what is happening and what is being done by third parties, they very rapidly respond to that as, if you will, a source of competition.

And their ability and their incentive to improve their own programs is enhanced dramatically just simply by having other parties who can compete with them for the opportunity to develop that resource.

I agree with the comments that there are places for both utility programs as well as third parties. I think some markets are served better directly by utility programs, but I think the third parties will help spur that development of those programs and make the market move much faster than it would without them included in the bill.

Senator WIRTH. Let me ask you all to think about comments on whether others have said—and let me go to Mr. Bar-Lev if I might briefly and then I want to come back to each of you for items that you would like to get into the record or comments you would like to make on what has been said either by this panel or the previous panel.

My own predilection, as you know, is to include as much economic incentive as we possibly can in making the transition. You move the fences not by regulatory fiat, but because moving the fences sells more tickets to the ballpark—and it really is getting threadbare, I am sorry—but that is where I would like to see us go in this legislation.

Let me ask you, if I might, Mr. Bar-Lev, what justification was there for the initial size limitation that was in PURPA? Was that a justification that was based upon an analysis of what was possible or what was feasible? Was that an arbitrary number? Where did that come from?

In other words, if we change it, are we going against the grain of a lot of analysis?

Mr. **Bar-Lev**. Senator, if you look back at the 1987 legislation that gave us two years' worth of the ability to build 80 megawatt plants, you will see in the record that FERC Chairperson Hesse and I believe also in the House Committee on Commerce's explanation of the bill. They said they could find no legislative history for the original limitation of 30 megawatts.

Senator **Wirth**. Have you been able to find it in the legislative history?

Mr. **Bar-Lev**. We have searched high and low and have never found any legislative history that explains the original limitation of 30 megawatts.

Senator **Wirth**. Let me go on further to say that there is a good deal of criticism of solar in the suggestion that it is not competitive economically going back to let us run this ship as much as we possibly can through good economics.

Now, when I was out at Luz and visited with your people out there, they said to me that the peaking—if I remember this properly and maybe you could correct this for the record—they told me that solar power at the Luz operation was now competitive with peaking power costs of, say, coal-fired power, and that the next iteration at Luz, the next facility that you all were going to build learning from the first two were going to bring that down to be competitive with overall electric power generation, and that finally they said that solar power has met all of the goals that have been set for it over the last decade.

Now, would you explain in a clearer way than I have where you are on the cost line at Luz? And second, where you think solar energy is at this point in terms of our expectations and plans for solar or aspirations for solar.

Mr. **Bar-Lev**. Well, that is a tall order, but let me try to answer it in this way. I think that if you do not count the cost of pollution that we avoid—we are not quite there, and that is why this piece of legislation is so important for us, because we feel as though if we could build to the economies of scale that we think are possible, we will bring it down because the evidence we have is that when we went from 30 to 80 megawatts we, in fact, reduced our cost by 25 percent.

Senator **Wirth**. Give me some quick numbers as to where you are.

Mr. **Bar-Lev**. Right now we are at eight cents per kilowatt hour for our 80 megawatt plant that we are building right now. What we believe is possible.

Senator **Wirth**. That compares to what?

Mr. **Bar-Lev**. Six cents.

Senator **Wirth**. So, you are at eight, they are at six.

Mr. **Bar-Lev**. Conventional energy plants are at six. We are at eight with the 80 megawatt plant. We believe that if you—if you let us build as large as we think we should be able to build, we will bring it down to six, and that is with today's technology.

We are putting a tremendous amount of R&D into the technology.

Senator **Wirth**. So, what you are saying is there is an arbitrary regulatory barrier to your ability to bring the cost of solar in in a way that it is competitive with conventional power generation?

Mr. Bar-Lev. That is exactly right.

Senator Wirth. Do you want to comment briefly on the second part of my question, sort of the mega-part where have we come and what is your sense of where solar is compared to the expectations that were made of solar and that we all had of solar in the seventies?

Mr. Bar-Lev. Well, I am not sure of what people's expectations were, but let me put it this way. In five years we have brought the cost of our plants down from 25 cents per kilowatt down to eight cents per kilowatt hour. We have proven that every plant can be built on time and on budget, and that is all in five years.

Energy technologies do not develop overnight. They require a tremendous amount of R&D, and they need the government policy to support them. And in this particular case, if you look at the environmental benefits that we have already provided, I believe that we have already met our promise.

In five years we have produced the environmental benefits. In five years we have brought our costs down. In five years we have shown that we can build on time, on schedule, and we are telling you that if you lift these limitations in a very short amount of time, a very short amount of time we are talking about in, you know, right away if we can build that size plant, we will be cost competitive.

In other words, what I am saying is that if you look at it in terms of a decade, in one decade we believe that we could start from zero and produce for you a cost-competitive energy technology that is environmentally benign.

Senator Wirth. It seems to me here we are with a good example of the need to remove regulatory barriers, those barriers being ones that have inhibited the ability of that segment of the energy marketplace to work properly.

Counsel has given me a note which I gather is the staff analysis that there was no policy rationale for limiting any of the small power producers to 80 or to 30 or whatever. It was, in their opinion, an arbitrary number not only for solar but any other power producer, whether it is biomass or whatever it might be.

Mr. Bar-Lev. That is correct.

Senator Wirth. Thank you very much. We appreciate your being here, and if there are other comments that you or your counsel would like to make on this, the record, as you know, will be left open.

Mr. Bar-Lev. I appreciate that opportunity.

Senator Wirth. Let me go down and ask all of you in closing if there are other comments you would like to make for the record. Let me just run down the line and start with you, if I might, Mr. Cohen.

Mr. Cohen. Yes, Senator. The only comment I wanted to make on the record was really in rebuttal to the testimony that was provided by the FERC staff and DOE on the measurement issue.

It is true that we are at the beginning of the learning curve of trying to track energy savings accurately, and it is also true that in some buildings measures in actuality will underperform engineering estimates.

I think the important point is that we are now learning how to calibrate real results and feed that back into our estimates. New England Electric will be spending something on the order of $5 million next year on measurement alone and trying to get a better fix on what happens in buildings. It is not an insoluble problem and should not be used as an excuse for withholding energy resources, demandside resources as a major contribution to the supply mix.

The last point I wanted to leave you with is just to underscore again that I think one of the most useful things the Federal Government could do to create the kind of process that is going on in New England is to provide or mandate the kind of proceeding that has been going on in New England for the last year or year and a half with intervenor funding to bring ideas to table and to get a lot of these specific strategies out in the open.

Senator WIRTH. Thank you very much.

Ms. Pastuszek?

Ms. PASTUSZEK. The comment that I would like to make is that PURPA was originally needed because generators of kilowatt hours needed a way to gain entry into the market, and I think that drawing the analogy to conservation suppliers is somewhat inaccurate because they are not barred from participating in the market.

There is a role, as Mr. Harding said, for both utilities and third parties to bring conservation into place. However, the posting of a price which is extending the PURPA model to conservation really takes utilities out of the business of being the primary supplier of conservation and puts them in the position of having to monitor all the third-party suppliers.

Just to follow on that, change is occurring in the utility industry, and I would encourage you to think about how much more quickly that change will occur if progressive utilities can show the strongest earnings and if jobs on the demand side become the profit center for the company. I think you will really see a dramatic change in the types of people who work at utilities and the types of ideas and attitudes and objectives that they have.

Senator WIRTH. Thank you very much, Ms. Pastuszek. I really appreciate your testimony.

I am reminded of the commitments of Sam Huntington. He would be, I think, very proud of the approach that you have taken and the clarity of your presentation.

Ms. PASTUSZEK. Thank you.

Senator WIRTH. I appreciate it very much. Please give my best to Mr. Rauh. That is a difficult set of shoes to fill there, but you are doing it very well, and we thank you.

Mr. Wolf?

Mr. WOLF. Mr. Chairman, just to reiterate, we believe this legislation provides not only the opportunity for third-party companies but also for utilities.

In the context of states that have gone to demandside bidding, we strongly recommend that that does not relieve the utility of its obligation or the opportunity to promote conservation and earn a profit on that should the current regulations provide for such in that state.

So we think the legislation is very complementary to the goals of getting both utilities and third-party companies to much more aggressively promote conservation.

Senator **Wirth**. Mr. Harding?

Mr. **Harding**. I would just like to reiterate, as Mr. Cohen has, that the implementation problems that were raised by FERC and the Department of Energy witnesses I believe are both soluble and, in fact, have been solved in past programs, both third-party and utility programs, over the last ten years.

Senator **Wirth**. We appreciate all of you being here. I think as I have listened to the testimony two weeks ago and today, everybody agrees on the advisability of removing disincentives for utilities to pursue conservation. Everybody agrees with that, and that is a step that we ought to take.

The questions then come as to should there be a second tier, and then what, as you pointed out, Mr. Cohen, should be in that second tier. There are a variety of alternatives, and it is in that area that I think we have narrowed down the discussion here with perhaps some drafting problems that were brought up earlier by Mr. Hobart. Maybe we had some drafting problems and rewards there that we do not mean to have.

Let us assume that everybody agrees on the first tier. It is what is in the second tier that is at issue here. If that is clear to everybody, should we put a second requirement in the legislation, or should that be left to State regulatory commissions working with utilities? There is a difference of opinion on that.

It is on that issue in particular that we would appreciate any written comments that you all might have on language that is in the legislation. I made that request earlier of our first panel of witnesses and of the FERC and DOE witnesses last week. They were very general in their criticism, and I asked them what exactly do they mean. We look forward to hearing from them and from you.

You have an enormous amount of expertise, and we appreciate that input. We will leave the record open, but we will really depend upon all of you for your commentary as well and your help.

Mr. Bar-Lev, we are doing our best. As you know, I believe that we ought to eliminate that ceiling which is arbitrarily in that legislation, and I appreciate your coming and helping us make the record. We cannot find any justification for it. We think that it was put in there just as a number. I think that your statement this morning is very convincing about the need to take that down to allow solar to compete in the marketplace.

We are not giving you anything. We are just taking away a barrier, as I understand it. Nobody is giving the solar energy industry anything, is that right? There is no taxpayer giveaway or regulatory giveaway or whatever it may be; is that right?

Mr. **Bar-Lev**. That is right.

Senator **Wirth**. All we are doing is eliminating a barrier and allowing you to build plants of the appropriate size that, in fact, can compete with traditional sources of power. It is as simple as that; is that right?

Mr. **Bar-Lev**. In fact, we are giving a benefit back to the American citizen because we will further reduce emissions.

Senator Wirth. We thank you all very much for being here. We thank our previous panel as well for their help and support. The committee will be adjourned.

[Whereupon, at 11:45 a.m. the hearing was adjourned.]

APPENDIX

Responses to Additional Questions

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

November 27, 1989

Honorable J. Bennett Johnston
Chairman, Committee on Energy and
  Natural Resources
U. S. Senate
Washington, D.C. 20510

Dear Mr. Chairman:

Thank you for your letter of November 9th enclosing questions for the record of your committee's October 26th hearing on PURPA-related provisions of S. 324, the "National Energy Policy Act of 1989."

Enclosed are my responses to the questions submitted by you and Senator Metzenbaum. If you need additional information or have any further questions, please let me know.

Sincerely,

J. Steven Herod
Director
Office of Electric Power Regulation

Enclosure

cc: Chairman Allday
Commissioner Moler
Commissioner Trabandt
Commission Langdon

Questions from Senator Johnston:

Question 1: Some conservation advocates argue that "demand-side options" (i.e., conservation) are not on a "level playing field" with traditional supply-side options. They argue that a utility should buy "conserved kilowatt-hours" whenever they are cheaper than "produced" kilowatt-hours. Others would argue that we cannot treat the two equally in any simple sense because the purchase of a conserved kWh is fundamentally different from the purchase of a produced kWh. In the former case, the utility confers a benefit on one customer that other customers must pay for. In the latter case, the utility buys a kWh and makes it available for sale to all its customers. Do you believe that some kind of "level playing field" is possible in this context? Or will we always have to view and evaluate supply-side and demand-side options according to different criteria?

Answer: These two positions are not exclusive. Demand-side alternatives need to be a part of any least cost strategy whether the outcome is determined through some formal planning mechanism or if it is produced through competition. However, it is also true that purchasing conservation is fundamentally different from purchasing supply because the conservation supplier receives two streams of benefits, payments from the utility and reduced electric bills, while the producer of electricity benefits are the payments for services provided. These differences must be accounted for in order to produce a truly least cost outcome. Various schemes have been devised at the state level to assure that economic conservation is being realized without creating any double payments for conservation that create unintended subsidies to conservation. The experience with bidding conservation directly against supply-side options is limited, but bidding concepts have been developed which would allow "head-to-head" competition without subsidizing the conservation options.

The Commission has not taken any position on how best to realize the economic benefits of conservation and demand management. There are many options available to the utilities and the state authorities which have regulatory control over retail markets. We will benefit from the diversity that is certain to result if the states and the utility companies are allowed to design programs tailored to their own particular circumstances.

Johnston Question 2: Some would argue that payments up to avoided cost for conservation raise economic efficiency questions. They would argue that a customer effectively gets a double payment for conserving. For every kWh conserved, he saves on his bill, then he gets a payment from the utility. If the combined benefit exceeds avoided cost, it might lead the customer to adopt an uneconomic conservation measure. In addition, the price increases to non-participating customers may lead them to adopt uneconomic conservation measures.

a. Are these legitimate concerns? Could conservation payments lead to significant economic inefficiencies?

b. If so, how might they be remedied? How could S. 324 be modified to address these concerns?

Answer: The so-called "double payment" problem is a legitimate concern. Testimony on this issues was offered by Charles Cicchetti on the second day of the Committee hearing. Dr. Cicchetti's testimony also discusses alternative mechanisms that could be utilized to assure that conservation investments are not subsidized. The basic mechanism to assure proper compensation for conservation is to pay the conserving entity the difference between the marginal cost of supplying electricity and the retail price for electricity.

The draft legislation seems to be sensitive to this problem in section 313(b), where it restricts the "rate paid for qualifying conservation to an amount no greater than: .... the amount by which the incremental cost of alternative electric energy exceeds the price paid by the customers whose demand for electric energy is reduced as a result of qualifying conservation." However, the same section of the bill also allows the ceiling price paid for the conservation to go up to the incremental cost of alternative electric energy without the subtraction of retail price of electricity. If this ceiling is used without the subtraction of the retail price, the double payment problem would be present. One obvious remedy for this problem is to limit the price paid for the conservation under all circumstances to the difference between the cost of alternative electric energy minus the retail price.

Johnston Question 3: Some analysts have argued that if a utility should pay for conservation (a customer investment that reduces his demand), why shouldn't the utility also pay a customer to self-generate with photovoltaics or a small diesel generator? These investments reduce demand just like conservation. Please comment on this argument and discuss any implications it has for S. 324.

Answer: If the price paid for load reduction, whether it is caused by conservation or self generation, is set correctly at the difference between the utility's marginal and average cost, conservation and self-generation will have the same result. The self-generation will have the same result. The self-generator's production costs will be offset by the combination of utility payments and reduced electricity bills. All producers and consumers of electricity will make their decisions based on the same retail and incremental cost signals. The objective of any procurement system designed to present a "level playing field" to all options is to allow all options to respond to the marginal cost of supplying electricity. To obtain this result, it is necessary to adjust the price paid for conservation by the retail price of the power conserved.

Johnston Question 4: The argument has been made that payments for conservation can create winners and losers among ratepayers but that this effect alone is not grounds for opposing such a program. However, the winners/losers effect should lead utilities and regulators to keep careful control over such programs, control that would be relatively hard to exert if utilities were required to buy conservation by a qualifying conservation entity. a.) Is this a legitimate public policy concern? Does the winners/losers effect create a serious equity problem? b.) If so, how could S. 324 be modified to address this problem?

Answer: The "winners/losers" effect, which is also known as the "no losers" test is indeed a legitimate policy concern. However, the problem can be dealt with effectively by restricting the price paid for conservation to the difference between the cost of alternative electric energy and the retail price of power. This pricing scheme allows conservation options to receive the correct marginal cost price without receiving a "double payment" or violating the "no losers" test.

As indicated in the response to question #2 above, S. 324 can best respond to this by restricting the price paid for conservation to the difference between the alternative cost of electricity minus the retail price.

Questions from Senator Metzenbaum

Question #1: Many state commissions have been giving long and hard thought to the myriad of policy options for spurring utility investment in energy efficiency. Some allow utilities to ratebase conservation, others permit utilities to recover lost revenues if their sales go down due to successful conservation, still others are working efficiency investments into their competitive bidding schemes for new power generation. Yet FERC has been virtually silent, except for passing mention of conservation in the now-dead notices of proposed rulemaking. Why the relative silence? Why doesn't FERC recommend policy options for the states to explore on energy efficiency just as you did with bidding?

Answer: Retail ratemaking is the responsibility of state authorities. FERC's regulation is limited to wholesale trade in interstate commerce. Conservation, by its very nature, is a retail function. As a result of this fundamental jurisdictional split between Federal and state authorities, the regulatory purview over conservation activities in the electric power industry has been, and is likely to remain primarily a state-level activity.

Recently there has been growing interest at the state-level to use competition (bidding) as a vehicle for procuring new power supplies. The Notices of Proposed Rulemaking (NOPRs) which were issued in March of 1988 were in response to this growing interest in competitive procurement in the industry. Since competitive procurement of new power supplies raises issues in the regulation of wholesale power trades, it was deemed appropriate by the Commission to explore possible modifications to existing regulations to accommodate these emerging competitive pressures. In the preparation of these NOPRs, the Commission noted that in order to assure efficient market outcomes in wholesale markets, it was appropriate to make the market available to all possible options, including demand-side alternatives. At the same time the Commission recognized the complexities involved in procuring demand-side alternatives and the primacy of state regulation in this area.

The NOPRs were designed to be totally neutral with respect to which alternatives succeeded in the emerging competitive electricity markets. However, special mention was made of demand-side alternatives to assure the states that FERC recognized the important role these retail options could play in the future, and to assure the states that they were free to design their competitive systems in whatever manner they saw fit, including giving demand-side alternatives a fair chance to realize their full economic potential, so long as the result could be judged "just and reasonable" under the Federal Power Act.

Metzenbaum Question 2: In the Notice of Proposed Rulemakings FERC tried to encourage a system of greater competition, at least among generation options. Do you believe that efficiency options should also be allowed to compete for utilities' investment dollars?

Answer: Yes. As indicated in the response to question #1, the NOPRs were intended to be completely neutral with respect to which alternatives succeeded in the emerging competitive marketplace. However, we also recognize that introducing demand-side alternatives into the competitive mix is complicated. Issues related to the "double-payment" problem and the "no-losers" test are discussed in response to Senator Johnston's questions, and are well presented in the testimony filed in the second day of the hearings by Dr. Charles Cicchetti of Harvard University.

Metzenbaum Question 3: What in your opinion are the three most important regulatory steps FERC can make toward encouraging cost-effective investments in energy efficiency?

Answer: The single most important step FERC can take to encourage cost effective investments in energy efficiency and energy supply, is to assure that our regulation under the Federal Power Act provides the necessary incentives for timely and efficient investments in any option that offers electricity consumers reliable supplies at the lowest possible cost. With the emergence of competition in the electric power generation sector, the Commission in March of 1988 chose to propose rules which were intended to refine our regulatory practices to better accommodate these competitive opportunities.

Beyond this, regulatory practices designed to cause prices to reflect marginal costs are important in improving the efficiency of consumption of electricity. To the extent that electricity prices under regulation at the state or Federal level can be made to accurately reflect the marginal cost of power, investments in conservation and demand management should reflect an economic consumer response.

A third area that could be important for encouraging cost-effective investment involves incentive regulation. As the industry enters a period where substantial new investment will be required to meet future power needs, it is important to provide the proper framework of incentives so that the investment decisions of the industry are not biased against the most economic alternatives, whether they be supply-side or demand-side options. To the extent free and fair competition is used to make these investment decisions, there is less reason for concern about biases in the mix of alternatives that result. However, if these investment decisions are not disciplined by the market, there is an increased burden on regulation to assure that the outcome is efficient. Much of the focus on "least-cost planning" that has surfaced in the past few years reflects the concern by regulators that these investment decisions be made in a fair and unbiased manner.

Metzenbaum Question 4: When a FERC jurisdictional electric utility comes before you for a rate increase due to new construction, do you evaluate whether the utility has already exhausted all cost-effective conservation investments?

Answer: As a part of the Commission's current rules utilities which request Construction Work In Progress (CWIP) for new facilities must file a statement BM (Reg. § 35.13(38)) which requires the utility to delineate the costs of alternative strategies including load management and conservation measures.

Admittedly this requirement probably has a limited effect on industry practices in the area of demand management. Since the states have jurisdiction over retail electricity trade, the oversight of the utilities' programs with respect to the balance between demand-side and supply-side alternatives is best conducted at the state level. This explains the surge of interest at the state level in pursuing "least-cost planning" programs. Typically, FERC regulates only a small fraction of any utility's ratebase. The typical utility has 80-90% of its ratebase regulated at the state level. State regulation also has primary jurisdiction over the siting of new facilities. As a result of this jurisdictional split, most of the regulatory oversight concerning the prudence of any particular construction program is conducted at the state level.

This does not mean that FERC is a disinterested or uninvolved party with respect to these issues. Any wholesale customer can challenge any rate increase as being inappropriate on the grounds that the utility has not pursued other lower-cost alternatives. However, with the focus on the prudence of utility activities that goes on at the state level, these challenges are relatively infrequent at the Federal level.

Department of Energy
Washington, DC 20585

January 19, 1990

The Honorable J. Bennett Johnston
Chairman
Committee on Energy and Natural
Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Chairman:

On October 26, 1989, Deputy Under Secretary Linda G. Stuntz gave testimony on S. 324, the National Energy Policy Act of 1989 before the Committee on Energy and Natural Resources.

Following that hearing, you submitted written questions on behalf of yourself, Senator James A. McClure, Senator Timothy E. Wirth and Senator Howard M. Metzenbaum to supplement the record. Enclosed are the responses to those questions, which also have been sent to Senators McClure, Wirth and Metzenbaum.

If you have any questions, please have your staff call Michael Gilmore on 586-4277. He will be happy to assist.

Sincerely,

Joseph C. Karpinski

Joseph C. Karpinski
Principal Deputy Assistant Secretary
Congressional and Intergovernmental Affairs

Enclosures

Department of Energy
Washington, DC 20585

January 19, 1990

The Honorable J. Bennett Johnston
Chairman, Committee on Energy and
Natural Resources
United States Senate
Washington, DC 20510-6150

Dear Mr. Chairman:

Enclosed are the answers to the follow-up questions you provided us in your letter of November 9, 1989. These questions and answers pertain to Subtitle B of Title III of S.324, the "National Energy Policy Act of 1989."

Please contact me if I can be of further assistance.

Sincerely,

Linda G. Stuntz

Linda G. Stuntz
Deputy Under Secretary
Policy, Planning and Analysis

Enclosure

QUESTIONS FROM SENATOR JOHNSTON

Question 1: Some conservation advocates argue that "demand-side options" (i.e., conservation) are not on a "level playing field" with traditional supply-side options. They argue that a utility should buy "conserved" kilowatt-hours whenever they are cheaper than "produced" kilowatt-hours. Others would argue that we cannot treat the two equally in any simple sense because the purchase of a conserved kWh is fundamentally different from the purchase of a produced kWh. In the former case, the utility confers a benefit on one customer that other customers must pay for. In the latter case, the utility buys a kWh and makes it available for sale to all its customers.

Do you believe that some kind of "level playing field" is possible in this context? Or will we always have to view and evaluate supply-side and demand-side options according to different criteria?

Answer: A utility may invest directly in energy conservation measures when these investments are less costly than investments in additional electricity production, and the reward for doing so is commensurate with that available from alternative investments. Under these circumstances, the purchase of a conserved kWh is not merely "the utility conferring a benefit on one customer that other customers must pay for." Total revenues required from the utility's customers would be reduced because the conserved kWh enables the utility to avoid having to obtain more expensive generating capacity. In some cases, the average rate per kWh might increase, because fixed costs would be spread over fewer kWh sales. However, this effect would be temporary, and is primarily a result of average embedded cost pricing. The impact of this increase should be balanced against the efficiency gains of acquiring a cheaper resource.

Answer 1
(continued):

It probably is too early to tell whether or not a truly "level playing field" is possible between demand-side and generating-side resources. Clearly, however, policy and regulatory action can be taken to make the playing field more level than it is now. First, we should improve the pricing mechanism by better internalizing important external costs and benefits and assuring that energy prices reflect marginal rather than average costs. Second, so long as utilities obtain greater profitability by selling additional electricity (the virtually universal tenet of current rate regulation), utilities will find it difficult to pursue measures that reduce sales. Various States are grappling with this problem in different ways. DOE, through its LCUP program, is also working at this issue and trying to help the States find the best answers, given their different resources, future demand projections, and new supply options.

Energy supply and energy conservation should compete in the marketplace on the basis of their relative prices and value to consumers.

QUESTIONS FROM SENATOR JOHNSTON

Question 2 (a):	Some would argue that payments up to avoided cost for conservation raise economic efficiency questions. They would argue that a customer effectively gets a double payment for conserving. For every kWh conserved, he saves on his bill, then he gets a payment from the utility. If the combined benefit exceeds avoided cost, it might lead the customer to adopt an uneconomic conservation measure. In addition, the price increase to non-participating customers may lead them to adopt uneconomic conservation measures. Are these legitimate concerns? Could conservation payments lead to significant economic inefficiencies?
Answer:	We have seen already that administered pricing schemes, such as that established in PURPA, can be particularly susceptible to inefficient results. The administratively determined "avoided cost" can be too high or too low. Even if it is set at the "correct" level, payments for conservation could lead to significant economic inefficiencies for the reasons you outline.

QUESTIONS FROM SENATOR JOHNSTON

Question 2 (b): If so, how might they be remedied? How could S. 324 be modified to address these concerns?

Answer: These economic efficiency concerns can be reduced by avoiding an administered pricing system and allowing conservation investments to compete with generation investments within an auction process, for example. The auction process would need to be carefully crafted to avoid the "double payment" difficulty you point out. This process would furnish a more level playing field for conservation investments if energy prices accurately reflect the costs that energy production imposes upon society, and if utility earnings are not penalized by investments in conservation.

S. 324 might be modified to require regulators to consider regulatory methods (such as ERAM used in California) of decoupling utility sales and profits. This could eliminate the disincentive to invest in conservation that a utility might otherwise have.

QUESTIONS FROM SENATOR JOHNSTON

Question 3: Some analysts have argued that if a utility should pay for conservation (a customer investment that reduces his demand), why shouldn't the utility also pay a customer to self-generate with photovoltaics or a small diesel generator? These investments reduce demand just like conservation.

Please comment on this argument and discuss any implications it has for S. 324.

Answer: This question points out the possibility that payments for conservation could distort economically efficient investment. Utility payments for conservation should be viewed as payments for utility load reductions. Utilities, State regulators, and the Federal government should not be concerned whether these utility load reductions are achieved through investments in energy conservation or through investments in alternative sources of supply (e.g., photovoltaics or diesel generators). The only criterion should be that the benefits from these investments exceed their cost, taking into account the potential economic inefficiencies that could derive from the "double counting" problem, and assuring that all externalities (e.g., environmental and supply dependency) are internalized for all fuel sources.

On this basis, consumers should be rewarded for reducing demand on the utility's system, regardless of how that reduction is achieved. Presumably, utilities and consumers will pay for demand reductions or self-generation only when it is in their own self-interest; i.e., when benefits exceed costs. Therefore, LCUP programs and S. 324 should not be concerned about how load reduction is achieved, but only that

Answer 3
(continued)

overall payments for LCUP activities do not exceed overall benefits. In some cases, States may find it desirable to pay for both self-generation and conservation options. Experiments along these lines should be encouraged.

Difficulties could arise, however, if customers and utilities are subjected to different environmental compliance costs for utilizing the same technology. For instance, if externalities are not considered on both the utility and consumer sides of the meter, payments might be made to induce customers to generate their own power in less efficient oil-fired diesel generators.

"Externalities" play a critical role in evaluating least-cost options. In other words, if we internalize these costs for one fuel cycle, electricity, and drive some users to other fuel cycles where externalities are not yet internalized, we may cause distortions which would not have occurred if externalities were treated equivalently within both fuel cycles.

QUESTIONS FROM SENATOR JOHNSTON

Question 4 (a): The argument has been made that payments for conservation can create winners and losers among ratepayers but that this effect alone is not grounds for opposing such a program. However, the winners/losers effect should lead utilities and regulators to keep careful control over such programs, control that would be relatively hard to exert if utilities were *required* to buy conservation by a qualifying conservation entity.

Is this a legitimate public policy concern? Does the winners/losers effect create a serious equity problem?

Answer: Yes, there would be a concern if utilities were required to purchase conservation *without* taking into account factors important to their ratepayers, including the creation of possible "losers" and the double counting problem.

These concerns are minimized by allowing local utilities and regulatory authorities to design and implement programs which meet local needs rather than mandating a particular approach or methodology.

QUESTIONS FROM SENATOR JOHNSTON

Question 4 (b): If so, how could S. 324 be modified to address this problem?

Answer: S. 324's requirement that utilities purchase qualifying conservation from qualifying conservation entities could be modified to require that State regulators consider ratemaking methodologies (such as ERAM, used in California) which decouple utility sales and profits. This could eliminate the disincentive to invest in conservation that a utility might otherwise have under present regulation in most States, where every kWh conserved reduces profits. In almost all States today, utilities obtain greater profitability by selling additional electricity. Therefore, they have little incentive to pursue measures which reduce sales. A "true-up" mechanism would, either retroactively or prospectively, "give back" to the utility profits lost from conservation-caused sales decreases.

QUESTION FROM SENATOR WIRTH

Question 1: **I want to ask you one question on an issue related to the topics we are addressing today. Recently, we have heard from renewable energy facilities that qualify under PURPA about the current restrictions on the size of their plants. I am referring specifically to the Luz solar thermal facility in California. Do you think it makes sense to expand the size limitation for renewable energy facilities covered by PURPA? Does the Department have a formal position yet?**

Answer: PURPA was implemented to encourage energy conservation and to promote development of small scale renewable energy facilities which would not otherwise be developed. The size limitation on renewable energy facilities imposed by PURPA regulations is unnecessary and may inhibit development of some efficient resources. Additional economies of scale for solar installations above the current 80 MW size limitation appear to be achievable. Increasing the size limitation, or removing it altogether, would encourage development of these larger resources. The Department supports the development of efficient, renewable resources that compete with other supply options. To the extent that development of these resources is artificially constrained (e.g., by size limitations), these constraints should be removed.

QUESTIONS FROM SENATOR METZENBAUM

Question 1: Your testimony leaves the impression to a degree that DOE's main role in utility conservation programs is to supply "a wide range of ongoing research, information and development activities." Are these activities all of a technical nature or do they include development of innovative policy and regulatory responses? What are the most exciting and important policy and regulatory approaches to energy efficiency that are coming out of DOE?

Answer: The Federal government regulates wholesale electricity transactions and conducts technology research and development and policy analysis and development. The States regulate the majority of the electric power market, including the acquisition of generating and demand-side resources. We believe that one of the most productive roles the DOE can play is to sponsor and encourage research into the many aspects of utility conservation and demand-side management programs, methodologies, and technologies, and to disseminate this information to utilities, local regulatory agencies, and consumers so that programs can be designed and implemented to meet local needs.

These activities include analyses of policy and regulatory approaches advocated and tested on the basis of actual experience with LCUP programs at the State and utility level. DOE activities also comprise analyses of methods to accurately measure benefits resulting from conservation activities, assessments of fuel cycle costs, regulatory procedures to reward utilities for energy conservation investments, encouragement of the adoption by State and local jurisdictions of energy efficiency standards for buildings, design and promulgation of cost-effective efficiency standards for appliances,

Answer 1
(continued)

and analyses of regulatory or policy options to improve lighting efficiency. These and other conservation policy and technology options are being assessed by DOE in conjunction with development of the National Energy Strategy.

QUESTIONS FROM SENATOR METZENBAUM

Question 2: What, in your opinion, are the three most important steps the Department of Energy can make toward encouraging cost-effective investments in energy efficiency in the utility sector?

Answer: The Department can encourage cost-effective investments in end-use energy efficiency programs by: (1) identifying and suggesting ways to remove current regulatory disincentives to utility investment in energy efficiency; e.g., use of the "true-up" mechanism; (2) continuing and expanding its Least Cost Utility Planning program; and (3) encouraging the adoption by State and local jurisdictions of energy efficiency standards for buildings, and promulgating cost-effective appliance efficiency standards. In addition, as part of the National Energy Strategy development process, the Department is considering other options believed by some to offer supply side energy efficiencies. These options include amending the Public Utility Holding Company Act, encouraging greater competition in electricity generation, and new transmission access policies.

QUESTIONS FROM SENATOR METZENBAUM

Question 3: Comparing electricity supply and demand options is very difficult, even for the best intentioned utility company. What research, if any, has DOE done on estimating a dollar value of the environmental benefits of energy conservation?

Answer: The DOE Least-Cost Utility Program (LCUP) is examining the environmental benefits of demand- and supply-side management options. One recently completed LCUP analysis undertaken by the Center for Clean Air Policy compared the cost of utility conservation options in the Tennessee Valley Authority and American Electric Power service areas with the cost of technological controls (such as scrubbers) for reducing emissions (mainly from coal-fired power plants). The study found that, under the supply and demand conditions extant in the two services areas, conservation was a cost-effective option. The significance of the study was in showing that demand-side management options can reduce the cost to utilities and ratepayers of controlling the emissions of acid rain precursors and carbon dioxide.

Another recent DOE initiative in this area included a LCUP program research assessment undertaken in collaboration with the Conservation Committee of the National Association of Regulatory Utility Commissioners among others. The assessment pointed out the importance of measuring and quantifying the

Answer 3 (continued): environmental impacts of energy use. Though the survey did not get into this level of detail, DOE recognizes that substantial analytical problems exist in measuring and quantifying energy-related environmental impacts. The DOE LCUP program is currently assisting utilities and public utility commissioners in 1) developing methods of measuring the environmental benefits of energy conservation and 2) incorporating environmental costs and benefits into planning and regulatory decisions. Research activities are being conducted in cooperation with various organizations including: U.S. Environmental Protection Agency, National Association of Regulatory Utility Commissioners, Edison Electric Institute, Electric Power Research Institute, National Audubon Society, Resources for the Future, World Resources Institute, and other environmental and consumer interest groups.

QUESTIONS FROM SENATOR METZENBAUM

Question 4: Does D.O.E. work with energy service companies and other independent providers of energy conservation services? Have you done research or other work that will help these firms expand their role? What do you see as the economic prospects of the energy conservation industry? What steps can we take to help promote their viability?

Answer: The Department works with both energy service companies and independent providers of energy conservation services. There is a fundamental difference between these types of companies. An energy service company usually provides a complete set of engineering services, management and hardware to a facility owner in order to improve the energy efficiency of the facility. In most instances this service is provided on the basis of a performance contract which guarantees the facility owner that the systems which are installed will perform as planned. Most other independent providers of energy conservation services sell specific energy conservation measures or services for a fixed fee.

Much of our research and development work is done on a competitive basis in collaboration with the industries that produce and sell specific kinds of energy hardware, such as heat pumps, energy control systems, lights, motors, etc. We hope that working with these companies will help move the technology into the marketplace faster and will keep them competitive in the energy service industry.

We believe that energy service companies using shared energy savings contracts offer a significant opportunity for improving energy efficiency in Federal facilities. All Federal agencies, including the Department of Energy, are required to implement a shared energy savings contracting program that will use the services of these companies.

In order to stimulate the use of shared energy savings contracting, the Department offers assistance to other agencies in developing solicitations for these contracts. In addition, we offer a course in Shared Energy Savings through the General Services Administration Training Centers periodically throughout the year.

QUESTIONS FROM SENATOR McCLURE

RE: Least-cost supply -- Section 311

Question 1 (a):	What should the Federal role be in encouraging gas and electric utilities to utilize least-cost supply planning?
Answer:	The Federal role should be one of providing funding for research and analysis of the many issues involved in least-cost planning activities and disseminating the results of these analyses to utilities, State regulatory commissions and other interested parties. The Federal role also should include informing consumers, manufacturers, utilities, regulators, and others about the benefits of cost-effective investments in energy conservation, and how least-cost planning processes can bring these investments about. The government as a major producer, distributor, and consumer of energy can play a role as a catalyst in bringing these disparate viewpoints and interests together to arrive at a consensus regarding data, methods, and objectives. The Department is exploring mechanisms to more effectively employ Federal power entities, the LCUP program, and the Federal Energy Management Program, including market mechanisms, in this capacity.

QUESTIONS FROM SENATOR McCLURE

Question 1 (b):	Are there any differences between gas utilities and electric utilities which would require that different standards or approaches be used?
Answer:	To the extent that the Federal role is limited to encouraging cost-effective least-cost planning activities, the same approach can be used for both gas and electric utilities. In both instances, establishment of particular standards or procedures should remain with local utilities and regulatory authorities.

Any more expansive Federal role must recognize the differences between gas and electric utilities. Gas utilities buy and resell natural gas. A gas utility must purchase gas for its customers in accordance with a least-cost purchasing standard administered by a State PUC. Amounts spent for purchases of gas found not to be in accord with a least-cost purchasing strategy are disallowed.

Electric utilities are more vertically integrated. Many produce the product they sell, and they have many different choices as to how they obtain electricity for their customers. Providing a disciplined process in which to evaluate the multiple options for generating or obtaining electricity is at the center of the least-cost planning process as it has developed to date.

Although New York and a few other States have recently begun to look at the application of LCUP processes to gas utilities, the

Answer 1 (b)
(continued)

understanding of this concept is much less well developed for gas than it is for electric utilities. An important reason might be that electricity's uses are many and complex, thus presenting many opportunities for increasing efficiency. Gas is used primarily for heating and industrial processes where opportunities for significant efficiency improvements are more limited.

QUESTIONS FROM SENATOR McCLURE

Question 1 (c): Would Section 311 apply to intrastate gas pipelines, and should it?

Answer: Section 311(d) would establish two tests to determine if a company is a "gas utility" under the bill -- the company must sell gas to an ultimate consumer and a State regulatory authority must have ratemaking authority over the company.

Section 311 appears to apply to many intrastate pipelines. Most, but not necessarily all, intrastate pipelines make sales to "ultimate consumers," mostly large industrial customers. In addition, most intrastate pipelines are subject to the ratemaking authority of a State regulatory commission. Thus, some intrastate pipelines would be covered, but others might not be.

We believe that coverage of intrastate pipelines is unnecessary from an economic efficiency perspective. Most of the sales made by intrastate pipelines directly to consumers are made to large industrial customers. These customers are knowledgeable and informed energy buyers who have both the incentive and the economic leverage to make "least cost" energy decisions.

QUESTIONS FROM SENATOR McCLURE

Question 2: Would Section 311 require least-cost investment, as the section title suggests, or least-cost supply, as the provisions of the section suggest? Are there any differences between the two?

Answer: This section appears to require States to consider any method which would encourage least-cost investments by local gas and electric utilities. The assumption seems to be that least-cost investments will produce the least-cost supply; including within "supply" both generating and demand-side resources.

QUESTIONS FROM SENATOR McCLURE

Question 3 (a): Should least-cost supply planning be more narrowly tailored towards life-cycle costing, or tailored more broadly to include external factors such as environmental factors, as Section 311 provides?

Answer: Life-cycle costing generally entails an effort to identify and quantify all the elements of a fuel cycle, including environmental impacts. LCUP programs should include the cost of environmental and other externalities (e.g., supply security) to the extent possible. To the extent that the cost of environmental externalities is included in various supply options (e.g., through requirements imposed by environmental regulation), LCUP will reflect the cost of these environmental factors. However, some environmental factors associated with energy production and consumption (e.g., CO_2 emissions) are not currently internalized within LCUP programs, or, perhaps are understated (e.g., SO_2 and NO_x emissions, or disposal of scrubber sludge). The problem is how to accurately measure these environmental costs and benefits and how to assign an appropriate value or cost to each.

This problem of measuring and quantifying environmental impacts has been identified by a recent DOE survey of LCUP programs as a major issue requiring further investigation and analysis. Until methodologies are developed which accurately identify and evaluate

Answer 3 (a)
(continued)

these factors, any Federal standard requiring utilities and regulators to internalize these factors within least-cost planning programs could be premature, and perhaps counterproductive.

QUESTIONS FROM SENATOR McCLURE

Question 3 (b): How would a utility take into account such factors? For example, how would it take into account the impact of acid rain on fish and wildlife?

Answer: It would be difficult for a utility to accurately determine the impact of acid rain on the environment and then to place a value (or price) on that impact. Progress is being made at the State level in developing assumptions as to the value of these impacts, but these assumptions are based less on empirical evidence than on political consensus. Consumers in one part of the Nation may place a greater value on a fish than consumers elsewhere. This is one reason why a Federal "schedule of external costs" is not appropriate.

The Administration is seeking to incorporate as an integral part of utility planning the costs of environmental impacts. For example, under the Administration's clean air proposal, the impact of acid rain precursor emissions on the environment would be reflected in the cost of fossil-fueled electric generation. If in a particular instance, this requirement increases the cost of electricity produced from these fuels, say from 4.0 cents/kWh to 4.5 cents/kWh, investments in energy conservation and demand-side management programs would become relatively more attractive. Moreover, because "allowances" must be purchased to cover fossil fuel emissions, it is economically efficient for the utility to invest in additional demand management activities up to the point where the cost of reducing consumption is equal to the cost of purchasing allowances for generation. The cost of the

Answer 3 (b)
(continued)

allowances, in essence, reflects the value placed on reducing acid rain emissions.

QUESTIONS FROM SENATOR McCLURE

Question 4 (a): Are State regulated utilities, non-regulated utilities and Federally regulated utilities treated differently by Section 311?

Answer: Yes. For State regulated utilities, section 311 would require that State regulators consider implementing a Federal standard which would provide an incentive return on investments in least-cost supply measures. Presumably, this incentive return would be in addition to utility recovery of the costs incurred in implementing these measures. For non-regulated utilities, section 311 would require only that these utilities consider implementation of least-cost supply measures. No additional incentive is provided. Federally regulated utilities (i.e., Federal power marketing agencies, TVA, etc.) are not affected by the provisions of the section.

QUESTIONS FROM SENATOR McCLURE

Question 4 (b): What is the status of such entities as TVA, BPA, NWPPC and WAPA under Section 311?

Answer: These entities are not affected by section 311.

QUESTIONS FROM SENATOR McCLURE

Question 5: **Since many electric utilities are partially State jurisdictional and partially Federally jurisdictional, what would occur in those cases?**

Answer: Section 311 would apply to all electric utilities, both regulated (i.e., investor-owned utilities) and non-regulated (e.g., cooperative and municipal utilities) at the retail level. Therefore, the requirements of section 311 would not directly affect wholesale (i.e., Federal jurisdictional) sales. However, to the extent that all utilities were subject to least-cost planning standards of the type set forth in section 311, utilities most likely would undertake wholesale purchases of electricity only if these purchases were "least-cost supply measures." That is, the cost of wholesale purchases would be considered in the LCUP process along with the cost of other supply options. Wholesale purchases would be undertaken only if their cost was less than that of the alternatives.

Even without S. 324, under current law we believe that any State may disallow a wholesale power purchase if that State determines that the wholesale purchase is not the "least-cost" option.

QUESTIONS FROM SENATOR McCLURE

Question 6: Why is it necessary to require State utility commissions and others to consider least cost planning? Why aren't they initiating it on their own?

Answer: As pointed out in our testimony on S. 324, State commissions and utilities are considering and implementing least-cost planning. A recent survey conducted by the utility industry identifies 43 States that are actively pursuing or contemplating LCUP activities. We believe that State commissions and utilities have incentives to pursue these activities in order to keep consumer rates low, to enable electricity to compete with other energy sources, to attract and maintain an industrial base, to avoid customer by-pass of utility services, etc. For these and other reasons, the Department believes that S. 324 is unnecessary.

QUESTIONS FROM SENATOR McCLURE

Question 7: What are the implications for long-term supply reliability and fuel choice of the adoption of a least-cost supply strategy for electric utilities? For gas utilities?

Answer: There is no one "least-cost supply strategy" for gas or for electric utilities. Depending upon the values assigned to various external costs (e.g., environmental costs), investment clearly could be skewed away from fossil-fueled generating capacity, and from generating capacity in general. If the estimated benefits of a conservation investment turn out to be wrong, and generating margins are allowed to deteriorate because of too much concern for short-term cost minimization, there could be an impact on reliability.

The Department of Energy is very concerned about adequate, reliable supplies of electricity for the short- and long-term. Cost-effective conservation initiatives, although a crucial resource, will not eliminate the need for new generating plants, but could moderate growth rates in electricity demand. The planning process already is complex. Adding further complexities (e.g., Clean Air Act amendments, conservation programs, etc.) increases the difficulty of planning for an adequate and reliable electricity supply. We want to aggressively exploit the abundant conservation resource. However, it is important to proceed with LCUP in a manner that does not harm the ability of utilities to supply electric power when it is needed.

QUESTIONS FROM SENATOR McCLURE

Question 8: Is Section 311 discretionary or mandatory?

Answer: Section 311 would mandate that each State and "each non-regulated utility" consider a Federal standard concerning least-cost supply options. Implementation of that standard would be mandatory only to the extent it is determined to be appropriate and consistent with otherwise applicable State law.

QUESTIONS FROM SENATOR McCLURE

RE: Payments for Conservation -- Section 312

Question 1: **Should this provision be designed to reward reductions in existing demand, or reductions in future demand which, but for the conservation measures, would occur -- or both?**

Answer: The objective of section 312 seems to be to encourage conservation that would not otherwise occur, now and in the future. As stated in the DOE testimony, we have serious concerns regarding forecasting of future energy consumption, measurement of the impact of conservation activities on energy consumption over time, determination of conservation which would not otherwise occur but for those actions taken under this provision, etc. Therefore, the Department does not support enactment of this provision. However, we support the concept of State regulators considering ratemaking mechanisms which remove regulatory barriers to conservation activities.

QUESTIONS FROM SENATOR McCLURE

Question 2: **Under Section 312, would the shifting of demand from on-peak to off-peak qualify as conservation, or is the conservation envisioned by this section only reductions in total demand?**

Answer: This section appears to include as "qualifying conservation" any reduction in the demand for electricity "at any time," which would not otherwise occur. This definition is silent about concomitant increases in demand in other periods, and presumably could include a shift in demand from on-peak to off-peak periods.

Shifting demand from on-peak to off-peak may produce real benefits to the utility because off-peak generation generally is more efficient (i.e., uses less fuel to generate the same amount of electricity) than on-peak generation. However, the difficulty is to accurately determine: (1) the amount of consumption shifted to off-peak periods; (2) whether this shift is due to "qualifying conservation" activities or to other circumstances (e.g., declining market for an industrial's product); (3) whether the shift is permanent or temporary; and (4) whether the shift improves energy efficiency. Actual experience by utilities and State regulators shows that peaks can be shifted, especially to shoulder periods, but with varying benefits and drawbacks to the system.

QUESTIONS FROM SENATOR McCLURE

Question 3. Is it desirable for electric utilities to own qualified conservation entities? Does the bill allow it to occur?

Answer: Section 312 (B) (ii) defines a "qualifying conservation entity" as any person not primarily engaged in the generation or sale of electric power, other than as a cogenerator or small power producer. This provision would exclude electric utilities from being a majority owner of a qualifying conservation entity.

It seems contrary to the objectives of this legislation to exclude utilities, who are very knowledgeable about their markets, from being "qualifying conservation entities." On the other hand, there is a potential for self-dealing or other cross-subsidization by a utility-owned qualifying conservation entity selling conservation to its parent at avoided cost.

One option for utility ownership would be to allow utility-owned conservation entities to operate only outside the parent's service area or zone of economic influence. Rather than excluding utilities from majority ownership in qualifying conservation entities, utility ownership of such entities could be addressed within a FERC

Answer 3
(continued)

rulemaking to implement the provisions of this bill, as provided in section 312 (B) (i). This may be a better method of determining appropriate utility ownership of these facilities.

QUESTIONS FROM SENATOR McCLURE

Question 4: It would appear that Section 312 would have certain classes of ratepayers subsidize conservation activities by other classes or ratepayers. Is that correct, and should such subsidies occur? From whom would the monies come from to pay qualified conservation? Would it be taken out of stockholder equity?

Answer: Section 312 would require electric utilities to purchase qualifying conservation from qualifying conservation entities only if this conservation would not occur except for payments made under this provision. In effect, some ratepayers will be paying other ratepayers to conserve. However, if that payment is less than what the paying ratepayers would otherwise bear to meet higher demand, it can be argued that the paying ratepayers are better off providing the "subsidy" than not providing it.

Monies to pay for qualifying conservation would come from the utility and, presumably, would be borne by ratepayers as a cost of service. However, there are few cases where utility recovery of investment is guaranteed, so shareholders might have some exposure as well.

QUESTIONS FROM SENATOR McCLURE

Question 5: **Is there anything to prevent a business from switching fuels in order to receive the electricity conservation payment?**

Answer: No, and to the extent that fuel switching represents a true cost reduction similar to that achieved through energy conservation, this type of activity should be permitted. However, it is crucial to take into account both environmental and supply security (e.g., oil dependency) externalities in all relevant fuel cycles. Otherwise, consumers could receive payments from utilities for switching from electricity to other fuels which, when all externalities are taken into account, may be higher cost options than electricity.

Another problem is establishing a baseline so that only fuel switching which would not otherwise have occurred is rewarded. We are concerned that implementing this provision would be very complex.

QUESTIONS FROM SENATOR McCLURE

Question 6: Would this provision encourage businesses to shut down in order to receive the electricity conservation payment?

Answer: The bill as written would appear to provide the opportunity for businesses which cease operation to qualify for an electricity conservation payment.

QUESTIONS FROM SENATOR McCLURE

Question 7: Under Section 312, who or what can be a "qualified conservation entity"?

Answer: Under this section, the FERC is given the authority to determine who may become a "qualified conservation entity." The only exception is that electric utilities are expressly prohibited from owning a majority interest in such entities. Implementing this section could become very complex.

QUESTIONS FROM SENATOR McCLURE

Question 8 (a): It would appear that Section 312 would require an electric utility to purchase unlimited amounts of conservation, regardless of a utility's need.

Is that correct, and would that be a good policy? What has our experience with PURPA QFs taught us?

Answer: The only explicit limitation placed on utility purchases from qualifying conservation entities by section 312 is that these purchases are to be made only to the extent that they would not otherwise occur. This may not be an effective limitation, because it would be very difficult for FERC or State commissions to determine what conservation would not otherwise occur.

As drafted, however, section 312 is "self-limiting" because purchases of qualifying conservation are made at a rate based on the utility's avoided cost. As additional "units" of qualifying conservation are purchased, the price paid by the utility declines. As the rate approaches the cost of new conservation measures, no further conservation will be offered and purchases will cease.

This "self-limiting" objective is important, but it may not work as the drafters of S. 324 envision because it relies on an administered pricing mechanism. To the extent that avoided cost estimates are too high or too low, inefficient investments in conservation may occur. This problem is one reason that States are including purchases of

Answer 8 (a)
(continued)

conservation measures within competitive bidding programs rather than extending the PURPA market to conservation. Since States are already empowered to extend the PURPA market to conservation, should they wish to do so, the Department believes that S. 324 is unnecessary.

QUESTIONS FROM SENATOR McCLURE

Question 8 (b): If a utility is required to purchase conservation in such quantities as to cause the idling of existing powerplants, what impact would that have on a utility's electric rates?

Answer: If a utility is required to purchase conservation in large enough quantities to cause the idling of existing plants, even if such purchases are at or below avoided cost (as required by this bill), the impact could be to cause electric rates to increase. This could occur where conservation significantly reduces sales, and the utility would be recovering its fixed costs, as well as the cost of conservation purchases, over a lower level of output. However, current DOE and utility community estimates of future electricity demand suggest that additional capacity will be required in most regions of the country even with aggressive conservation programs.

QUESTIONS FROM SENATOR McCLURE

Question 8 (c): Why shouldn't utilities be required to purchase only that amount of qualified conservation which is necessary to displace future powerplant construction?

Answer: Demand side management will not eliminate the need for new powerplants, which are likely to be needed in most regions of the country by the turn of the century.

Utilities may avoid both short-run costs (i.e., the costs of operating existing facilities), and long-run costs (i.e., the costs of building and operating new facilities). It makes sense for utilities to make investments in energy conservation and demand-side measures to the extent that the cost of these investments are less than the utility's avoided cost (either short-run or long-run). As stated in the response to the previous question, conservation may result in a temporary increase in rates to consumers. However, if the conservation is cost-effective and reduces the utility's revenue requirement, it may be preferable. The proper balancing of these considerations is best left to State regulators.

QUESTIONS FROM SENATOR McCLURE

Question 9: **Should the PURPA full avoided cost standard be changed so that utilities do not pay more for conservation than is appropriate?**

Answer: The PURPA avoided cost standard requires that rates (prices) for utility purchases from QFs should not exceed a utility's full avoided cost. It does not prevent purchases at prices below full avoided costs. FERC rules implementing PURPA have stressed that rates should be at full avoided costs. FERC is in the process of reevaluating its rules regarding avoided cost and has proposed competitive bidding mechanisms for purchases from QFs as a way to address this pricing problem. In addition, several States already have instituted bidding mechanisms which include demand-side options.

Including qualifying conservation entities within bidding programs may be a way of addressing the pricing issue. However, doing so raises a number of other issues related to the ability to accurately measure conservation costs and benefits, as well as the "double payment" issue.

The problem with PURPA's avoided cost standard stems from the difficulty in administratively determining a utility's avoided cost. In some instances, utility payments to QFs based on an estimate of the

Answer 9
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utility's future avoided cost have resulted in an overpayment to the QF. Similar results likely will occur from utility purchases from qualifying conservation entities (i.e., the "double payment" problem).

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